COMMITTEE WORKSHOP

BEFORE THE

CALIFORNIA ENERGY RESOURCES CONSERVATION

AND DEVELOPMENT COMMISSION

In the Matter of:)
) Docket No.
Preparation of the 2007) 06-IEP-1D
Integrated Energy Policy) 06-IEP-1M
Report (2007 IEPR))
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CALIFORNIA ENERGY COMMISSION

HEARING ROOM A

1516 NINTH STREET

SACRAMENTO, CALIFORNIA

THURSDAY, AUGUST 16, 2007

9:00 A.M.

Reported by:
John Cota
Contract No. 150-07-001

COMMISSIONERS PRESENT

Jackalyne Pfannenstiel, Presiding Member

James D. Boyd

Jeffrey D. Byron

John Geesman, Associate Member

CPUC COMMISSIONERS PRESENT

John Bohn

ADVISORS PRESENT

Suzanne Korosec

Steve St. Marie, CPUC

Tim Tutt

STAFF and CONTRACTORS PRESENT

Lou Barton, Global Energy Decisions

Leon D. Brathwaite

Ann T. Donnelly, PhD, Global Energy Decisions

Michael Donnelly, PhD, Global Energy Decisions

Catherine Elder, RW Beck, Inc.

James Fore

Gurinder Goel, Global Energy Decisions

Michael Jaske, PhD

Dave Larsen, Navigant Consulting

Mashariki Lawson

Dale M. Nesbitt, PhD, Altos Management Partners

Lorraine White

ALSO PRESENT

Jill Scotcher, Pacific Gas and Electric Company

Robert Brooks PhD, Robert Brooks & Associates

Eric Wanless, National Resources Defense Council
(via telephone)

Mark Minick, Southern California Edison

Larry Tobias, California Independent System
Operator

I N D E X

P R O C E E D I N G S

9:13 a.m.

MS. WHITE: Welcome everyone to the workshop today for the 2007 Integrated Energy Policy Report. Just some housekeeping items for those of you who are not familiar with the building. Out the double doors here and to your left you will find restrooms. There is also another set of restrooms behind the elevators. At the top of the stairs you will find a snack bar under our awning.

In the event of an emergency we ask that all of you please follow staff to our designated meeting area, which is across the street at the park, Roosevelt Park, and wait there until we have the high sign to return. If there is any questions about the facilities here just do let me know. And of course I can answer any questions you might have.

And like I said, it should just be a few minutes before we actually get hooked up with our call-in number.

(Off the record.)

PRESIDING MEMBER PFANNENSTIEL: We're going to get started even though the telecomm isn't set up yet. So whenever it is we'll have to be disrupted for a little while to get that operating. But we have a full agenda and a full crowd and a lot of ground to cover today. So I'd like to get started.

First of all welcome and thank you for coming to participate. This is a workshop of the Integrated Energy Policy Report Committee. The Committee is myself, I'm Jackie Pfannenstiel, the Chair of the Energy Commission, and John Geesman, who is to my right.

We are joined today by a lot of our partners in this. Let me go across the dais. To my far left is Commissioner John Bohn from the PUC. The PUC has been an active partner with us in the IEPR process So we are delighted that Commissioner Bohn is able to join us.

Next to Commissioner Bohn is Commissioner Boyd. Next to Commissioner Boyd is Commissioner Byron. Beyond Commissioner Geesman is his advisor, Suzanne Korosec. And next to Suzanne is my advisor, Tim Tutt, and next to Tim is Commissioner Bohn's advisor, Steve St. Marie. That's who we are.

We are, as I said, glad that all of you

are here to participate. This is actually a workshop on two separate but actually quite related subjects. There's the natural gas reference case projections and the scenario assessment of the electricity system.

And as you can see from the agenda that was outside we're going to start with the natural gas assessments. So let me turn it back over to Lorraine for introductions.

MS. WHITE: Thank you, Chairman. My name is Lorraine White. I am the program manager for the Integrated Energy Policy Report proceeding.

I would like to thank you for your patience in dealing with our delay this morning while we address a technical difficulty with our call-in number. The call-in number will actually be available by the time that we start our public comment and stakeholder comment process.

In the meantime this workshop is also being webcast from our Commission website so that parties can actually see the presentations and hear them, if not at this time being able to actually ask questions.

I have already covered some of the

logistics about the facilities here at the Energy Commission. Like I said, if you have any questions do let me know.

The materials for today's workshop are posted on our website as well as hard copies available in the entry area of the hearing room here so that people can follow along with the hard copies and then also with the electronic versions on our website.

When the call-in number is actually connected parties who would like to ask questions can dial in to 1-800-857-6618. The passcode is IEPR, I-E-P-R. My name is Lorraine White, I'm the call leader. Of course, all the information about this proceeding, the assessments that we've done, and the webcast for today is available on our website.

For those of you that would like to make comments, as you can see from the agenda there's two opportunities. One is going to be during the period when they're dealing with the natural gas assessments, our reference case projections as well as what we're doing with the scenario work. And then later we'll also have another comment period during our discussions on the aging plants.

So in the event that you do wish to ask questions we do have blue cards out in the front. It makes it a lot easier for us to make sure that we can actually call upon you when the time is appropriate to make your comments or questions.

As the Chairman has mentioned our agenda is rather packed today. We have a lot of information we'd like to cover about our staff revised assessment on natural gas projections for supply, demand, price and infrastructure issues. And then also discuss the work that we had done on the natural gas assessment in the scenario work and the results of different types of sensitivities that we did in that project.

In particular we will also be looking at our case 5-B that has load demand for natural gas in the electric generation sector. Later we'll also be hearing from our consultants who assisted us in look at alternative approaches to evaluating the uncertainties with the natural gas assessment.

And as I mentioned we'd like to have your comments and answer your questions if possible, look at the implications of this work on what we're doing in the IEPR and what might be done in the next steps.

We'll take a break in between that and our aging plant discussions where we'll look at issues associated with the retirement and replacement of older facilities.

Staff will provide an overview and an introduction of what we have done and then also what the technical evaluation is all about.

Again, opportunities for comments, discussions of implications of this work and what we'd like to do for next steps.

All of this work is associated with the Energy Commission's completion of what is required as part of our Integrated Energy Policy Report proceeding. We're tasked with doing assessments and developing forecasts on energy resource related supplies, demands and price and the infrastructure implications of providing the needs for the state.

From these assessments and forecasts we look at the associated issues, develop and recommend policies to address those issues and pursue different types of actions to achieve various goals that we set for ourselves.

In order to do this evaluation and develop these policies we're very dependant on input from parties, obtaining information from market participants, consulting with other agencies. We have benefitted a great deal from our sister agencies, particularly the PUC in developing this work.

The legislation requires that we do this assessment every two years with the intervening years being associated with specific topics being updated.

I had to adjust the schedule to insure that we can complete as much analysis as we possibly can in this proceeding. In particular we've engaged as part of this scenario analysis some really robust and thorough evaluations. And as you can see this discussion and analysis is ongoing.

We are looking at issuing the Committee Integrated Energy Policy Report that includes the results of these assessments, rather than in late August we're now looking at late September. And the idea is to hold hearings on this Integrated Energy Policy Report in October with the Committee's final report being issued in November. And we're targeting the November 21st regularly scheduled, business meeting to adopt the report and before the end of November transmitting that report to the Governor and Legislature for their consideration.

In terms of the work that we're doing on the natural gas assessment and the scenario evaluation, pardon me, we have requested that preliminary comments were submitted on the 13th. Those of you that have done so, we have benefitted from that in developing this workshop today.

We're also asking parties to provide us final comments on the discussions related to the natural gas assessment and our projections there in both the staff's natural gas work and the scenario work by the end of August.

There will be a fifth scenario evaluation-related workshop. This will focus on energy efficiency cases that we have developed recently to see what types of things that we can do even more aggressively to achieve greater energy efficiency and what the implications of that might be in a scenario evaluation.

We will be holding that workshop on September 17th. We expect to complete the natural gas-related assessment by the end of September and the total scenario evaluation by the end of

October.

This is just some contact information for parties in the event that you have any general questions. Feel free to ask me, of course. Specific questions I direct you to Dr. Mike Jaske. His contact is not only presented here in my slide but also in the notice. His email address and his phone number is there.

I direct you to Ruben Tavares if you have any specific questions about the materials you hear today or see on our website about staff's natural gas assessment. And if there are any questions about the more logistical things I'd be happy to answer them. If not, I'd like to pass this off now to Jim Fore for the staff's presentation on the natural gas assessment.

PRESIDING MEMBER PFANNENSTIEL: Thank you very much. Let's begin.

MR. FORE: Okay, good morning, Commissioners. We're going to handle the natural gas forecast maybe slightly different than we have in the past when we've reviewed it. We're going to talk basically about the difference between the original forecast made in June and the August forecast and go into some of the structural changes we made and see how it impacted the forecast itself without really talking about numbers in specific.

So really in the reference case what we're looking for in the long-term perspective over the next ten years. It's based on annual averages.

We're going to focus on the infrastructure and resource adequacy. And we do have some sensitivity analyses that we did not have in the reference case in June that we've included in this case.

The changes that were made to the --

ASSOCIATE MEMBER GEESMAN: Madame Chair, could we perhaps pause and get the screens so that they're legible. I know the staff has gone to great length to prepare the presentation. We ought to be able to comprehend it when they make it. You might also dim the lights so that the audience can see the screen.

MR. FORE: The first thing we made in terms of the change from the June to the August forecast, if you remember in the June forecast we allowed the model to run based solely on economic parameters without putting any limitations in the model in the areas.

So we're interested in what the potential was for LNG. And so we put in the capacity in the early years of the plants that were being built but then we allowed the model to add any extra capacity that it wanted to to flow economically LNG into the US.

After reviewing it we thought it was too aggressive in relation to the liquefaction capacity in the world and the competition we had elsewhere for LNG so we went back and we put in a capacity limit that started at today's level and basically built around a little over 14 Bcf by the end of the forecast period.

Now the volume of LNG that will flow in is still determined in the model. We've just limited to what was the capacity. And we knew this would fill because we had 24 Bcf coming in in the original case.

But we reduced the amount of LNG available to the north American market. Then there was really some concern here on the finding and development cost particularly in the Rockies whether we had covered the areas that are excluded from drilling or that have drilling limitations placed on them.

And so we went back and we revisited this. And we decided we had accounted for all of that so we made no changes in that. But that was one that was of concern.

In the Baja Mexico area, the San Diego Otay Mesa crossing that would bring LNG that landed in Baja into southern California. Again, we allowed the model originally to flow what it economically would flow. And it was much more than what the pipeline capacity was.

And our feeling was that the cost structure on that was not adequate in the model because it would have had to flow really gas all the way up into the LA market.

And getting a pipeline built through there would not really cover in the next ten years. So we limited the flow here to 400 MMcf per day which is the pipeline capacity from Mexico into the San Diego area.

The other area was the Alberta Oil Sands development. This was based on a study that was done in '03. And we updated the oil sand outlook and we greatly increased the amount of gas that was going to be demanded here in oil sands.

We looked at the production in June for California that was coming out of the model. It was higher than current rates. And we don't see California's production really increasing in gas. It may staying flat with the increase in drilling. And so we made an adjustment in the model to reduce the amount of supply that California would supply internally.

Power generation, we put in the latest forecast from the electricity office. We had been using the previous forecast they had used back in the '05 period. And so we updated that.

We did the same thing with the demand office. We had been using the '05 numbers that had been approved. And we updated that with what they presented here in July.

I'm going to go right to price because we usually save this for the last but this has a lot to do with what we're going to talk about later on. The old forecast is down here. This is our new forecast. It's higher. And it's higher because some of the structural changes we made as well as limitations we put on the LNG coming into the country.

This one is a lot more choppy. It has

to do with the number of iterations we ran. It would have been smoother if we ran the model longer. And it has to do with the way we brought in some of the capacity in lumps which drove the price up and down.

But we're going with the same base price up to a little over $7 in the new forecast. Okay, we have to remember that our residential, commercial and industrial sectors outside of California have an elasticity to them in relation to these factors.

And all of these factors here stayed constant in the revised forecast. The only thing that is changing is natural gas prices. And that does have some impact on the demand outside of California in the residential, commercial and industrial sectors.

And what we did here is, this is the inelastic, which is important later on. And the oil sands that are annualized to meet California demand are all considered inelastic. All of the other prices have an elasticity function that the model will address as it runs.

Okay if we look at the realized California gas demands we can see that it changes very, very little here. Basically it stayed the same but we did input the new gas forecast that we received in July into the model.

The basic change that you saw over there is right here in the power gen, the gas burn in the power gen was slightly higher so we have a little bit more there that caused the increase.

The other that we see, the total increase is very slight when you look at the total difference here. And basically we're coming in with power gen. We have the EOR went up slightly in the revised forecast in comparison to the June forecast, which is understandable with the price of oil being where it is today. We would expect production in that area to try at least to increase or stay the same.

Western Canada, since that is part of the electricity office demand forecast and Western US we put the new numbers in. Again, they're slightly higher. It has to do with basically the California demand increased and so we're seeing some dispatch from the western states and western Canada into the California market.

The big change in gas demand that was in the inelastic sector is coming here with the

Canadian Oil Sands. This forecast was based on work done back in, by the National Energy Board back in about the 2002/2003 time period.

They were assuming that the gas, that the oil prices would be about $22 a barrel constant, that Saudi Arabia would not allow it go below that. Well, Saudi Arabia is not worrying about the 22 bucks anymore. And we're up here now with the west Texas intermediate selling for about $72 a barrel.

And so there is a new forecast that has been put out by the Canadian Association of Petroleum Producers and the Province of Alberta. And we took their forecast and we, they have a high and a low and Alberta had just a single forecast.

And we averaged that and came up with a new forecast for the amount of bitumen that would be produced and then we ratioed the amount of in situ and mining that would be done and the gas requirements for those two types of processes to come up with our new gas demand for the Alberta Oil Sands.

And it peaked slightly above 2500. So you're looking at around 1500 difference out in here and a little bit higher difference at the start because these forecasts were initiated back in about the 2003, 2002 time period as their base year.

When we look then at then at the rest of North America and we're looking at the residential and commercial market here. We see that in the model it did respond to the price increase in that we have a slightly lower demand associated with the residential, commercial sector in North America.

In the industrial sector, again, we see a slightly lower demand. We still see in the old case if you remember the price was going down and that's why we saw somewhat of an incline here, then as the price increased in the old case it went down. Well the price is a little flatter, it doesn't show quite the fluctuation, but we still see the increase slightly and then it starts to taper off.

When you look at the North American inelastic natural gas demand this includes the oil shales, the oil sands and the California, that are all inelastic and we see that it is increased really I would say significantly in terms of the model. But these are all inelastic so they are not sensitive to the price. So they're put in and the model will then supply gas to these demand centers.

We looked at the change in North American gas demand. It doesn't change too much because the demand didn't change all that much. It went up basically with the oil sands. But the overall gas demand was not too much greater than it was in the previous case. So it's a little bit higher. The real choice will come here in the mix of how that is supplied.

If we take a look. This is the North American production. In the old case where we had the LNG coming in this was much wider and you saw this tapering off much more. So with the LNG being less we've had an increase here in North American production.

It's coming mainly out of the Rockies and out of Texas. And we'd associate that with the coalbed methane that is very active in the Rockies areas right now as far as drilling and reserves being put into production. And in Texas we would assume that their increase is going to come from the bartlett shales that are being actively pursued now in east Texas. And so the gas will come in at a higher price. But it will come in basically we feel in those two areas.

If we look at the LNG imports, this is what we had before. This is what we have now. So you can see that we really decreased these imports drastically. And that gas had to be made up from domestic production in North America.

If we look at where the LNG came in at, in the current model the east coast is flat. The little increase you see here is basically at the operating facilities, Cove Point and Elva Island, where they have expansion plans and they've actually done some expansion. And so you see this here.

Mexico we assumed would stay constant on the east coast. Let me jump up to Mexico west. This is where the Baja comes in. And we did allow an expansion out here, that's why you see the increase.

And Canada comes in. On the east coast it's the plant that's under construction with the Irving Oil Company which will supply gas to the refinery and into the New England area.

And then the bulk of the change is here

in the Gulf Coast and it includes expansion of Lake Charles and completion of the plants that are under construction at this time.

We did lag the plants somewhat because construction doesn't seem to be flowing as fast. We did limit in terms of the capacity to 75 per cent operating factor in order to come up with the amount of gas that would be coming into the US.

If we look at production, the California production, this is the adjustment we made. This is more in line with what we're seeing today. And we see it declining along the same trend we'd seen before in the model and so this is the new California gas supply that is being, that is being forecast by the model.

If we look at North American gas production we see it increases significantly out here as we drop the LNG off. In the early years your LNG is not that much different than it was in the original forecast because the increase in capacity was occurring out in here. So we're seeing that this is the natural gas that has to be made up by North American gas producers.

And if we take a look, now what we were concerned with is where California is getting its gas from and what the competitors would be doing that are asking for the same gas.

Western Canada, we see production basically as we've indicated before is peaked to flat. But this gas can also flow into the Chicago market all the way over to New England if it's priced right and so California is competing really with the rest of North America.

The Rockies has always been kind of considered a captive market for the west and California. We have a new pipeline that is going to be built called the Rockies Express which will put some demand for this gas going east.

The San Juan basically is still supplying gas for the west. The Anadarko and the Permian Basins will have major pipelines that go to the east. And so with not as much LNG coming in you look for our gas to be flowing out of these areas to make up for that as well as the additional gas that will be produced in Texas. And maybe some of the western Canadian gas will be drawn into the Chicago market because the price differential will not be what it was in the reference case.

Let's look at the infrastructure changes that we made in the model. We still had the Baja starting at 2008 at 1 Bcf. We bring it in in 2008 at one-fourth. We don't figure it's going to start up until the end of the year.

We then allowed the increase to where it runs at 75 percent of the capacity. We limited the pipeline capacity into San Diego to 400 Mcf per day. The north Baja will be reversed in 2008 when the LNG starts to flow.

The Rockies Express we have starting in 2009 at one Bcf. We allowed Baja to expand in 2015 by 1.5 Bcf. When it expands these two things occurred in the model. We did not make them happen. All of these were basically hardwired into the model. When Baja expands, the north Baja pipeline going into Blythe needs to expand. It can't push the gas into San Diego because we've limited the supply, the capacity of the pipeline into San Diego.

We're assuming that Mexico's gas demand won't grow that much because it's supplying basically the electric generation sector. And so that gas has got to move up north Baja into Blythe and then back into the southern California market.

Also what happens when this expands is

we find that we're getting real crowding basically in the southern California market so the rest of that gas has got to move somewhere else.

So what we saw was that Line 300 of PG&E expanded and so part of that gas then that's coming into California -- and it doesn't have to be LNG. It can be the stuff coming in from Kern or from El Paso North or Transwestern, will end up going up into the valley on Line 300. And the line expanded by roughly 500 Mcf in 2016. And it's really basically attributed to the expansion in the LNG.

This was the change we saw at Otay Mesa. This is what was in before. This is what we have in now. So you see there's a tremendous amount of gas that was originally moving into southern California by way of San Diego. This gas now basically is going around to Blythe and coming back in to the southern California market through the original source that comes in through Ehrenberg.

So it's displacing basically gas on El Paso South. And eventually later on when it expands we think maybe it's displacing some other gas. But there is a line that allows this to go north and that's why PG&E 300 expands.

If we look at California's natural gas supply and where it's coming from we have the LNG into San Diego. This is what's coming in. This is the part of the LNG that is coming in through Blythe by going up north Baja. This is the gas we have coming, that comes in from San Juan, the Rockies. They're staying fairly constant.

The California production tapers a little bit as you can see. Canadian gas falls off somewhat out here in the later on. And the Permian gas probably doesn't really go to zero but the model is basically saying that the flow is so small it's not accounting for it there.

If we look at the gas flows so we can see a little plainer what's happening on the different areas. This is the Otay Mesa. When it comes in we see the flow into Blythe has dropped. Now this is off of the El Paso system. When we add this back in we're really, the pipeline would be still holding on.

Malin goes down a little bit as LNG comes in and then it starts to build back out with Canadian then we have the drop-off off here at the end. Kern stays fairly constant. It does see the impact here with LNG. The Topock, which is basically El Paso North and Transwestern coming in, we see a little bit of an increase but again it's fairly flat through the time period.

And this is what I was talking about. When the LNG comes in here it either comes here into San Diego or it goes up and around and enters the SoCal system basically here. It would be coming this way and then coming into LA and back down into this area.

Again, because this gas is coming here the gas that would normally flow down into San Diego now is able to go here because this market is being supplied out of here. So we're seeing what, we would assume the gas would be moving basically into the LA basin until in essence we get too much and then it's got to find another way to go.

So if we look at the PG&E system what's happening is it's coming in, and it's -- but then when it comes up to here, after this fills up into the LA basin well then it has to come up and go up Line 300 and supply gas into here. So at the end of the forecast period, if the LNG expands like we say, the economics indicate it will come in and it will eventually reduce some of the gas requirements from outside of the state coming from the west or Canada because it will be moving into there.

If we look at what impact it has in terms of the national picture. The bars are the Henry Hub price. And you can see at the start of the forecast we have a fairly decent advantage compared to Henry Hub, a very good discount in here with the El Paso San Juan. Even the Canadian gas. This is where the LNG comes in at.

But as we get towards the end of the period we're not getting the great discount that we had here. Part of the reason is, is this gas price here is increasing slightly faster than Henry Hub. And we feel that the Henry Hub price is being held back because of the LNG flows coming into the Gulf Coast because it's competing directly with the gas at Henry Hub. And so we don't see as fast a growth rate in the price of Henry Hub as we do in terms of the increase in price for our gas.

On our border price we see that Malin ends up being a little bit higher in the forecast period as compared to Blythe and Topock and that differential is what we believe is causing, will cause the flow up Line 300 because it will be to the advantage of PG&E to come and get the gas down here that's cheaper rather than bringing in additional gas from Malin. And they will then go up and expand 300 and flow gas up the valley.

Okay, we ran some sensitivity cases. We have a dry hydro condition. We have one where we've added a Bcf of LNG into Southern California. I'll point out before I get to the graph. The dry hydro condition we have that we ran is a dry hydro for the entire ten year period so it would be about the most severe case that we would be able to model.

We then add a Bcf into Southern Cal that begins in 2012, and this is a utilization factor, and then we have an expansion. This is the difference between two and three is the expansion here. Then we looked at leaving the facility in Southern Cal but doing the additional facility up in the Pacific Northwest rather than putting it into the Southern California market.

What we see is a price differential on it. This is like 12.5 cents with Malin. Then we have the Topock and this is the Henry Hub price that varies slightly throughout the forecast period. But we can see that the LNG when it expands, we get more of a benefit from it.

To be perfectly honest, we have to find out what happened here. It shouldn't have we wouldn't think go down that far and we can determine if we had any change in capacity points in the model. We haven't been able to locate that. But the price would still be, we think, up in this area as far as the discount to California when received.

What happens on the flows when we see where this is the differentials. So this basically is lost flows that are coming in from the Southwest. The Rockies continue to basically maintain their flows, they're not impacted as much and the Canadian gas seems to be impacted. This is the LNG coming in from Mexico. We see a big reduction here when we open the LNG into Southern California but then it slowly builds back. But the main change --

ADVISOR TUTT: Excuse me, Mr. Fore.

MR. FORE: -- is probably price-related to supply the Canadian and the southwest gas have the greatest decrease.

ADVISOR TUTT: Jim.

MR. FORE: Yes.

ADVISOR TUTT: Are you talking about sensitivity number one, dry hydro, or an LNG increase here?

MR. FORE: I'm sorry. This is the dry hydro. And so what we're seeing here, these are positive. This is where we're going to -- when we get this we're going to have additional gas that has to be burned. So yes, I made a mistake, I was jumping ahead here. So this is the -- With the dry hydro we're going to have to have more gas and so these really are positive here. And the same way with the flows, we've got to make up.

Then when we go to the LNG in Southern California now we see the negative deal. I was just in so much of a hurry to get here. We see a loss in, again Malin, Topock. And we have the Henry Hub price is down slightly but the main difference, of course Topock is in the south so it suffers the greatest decrease in the early stages of the LNG coming in.

Then when we do the expansion we're seeing here the flow difference. Again we have a minus here for the Southwest. This is the LNG in the Southern California, which is positive. We're using that 75 percent factor on the one Bcf and that's why we don't see it going up to one Bcf here. But it does fill up and it displaces basically the gas coming out of the Southeast -- Southwest. Very little impact on the Rockies but some and California production is impacted slightly.

The price differences with it coming in. Malin is, all of them dropped. And the biggest drops are the gas coming in through Topock and through the southern part of the system. It's where you're seeing the greatest decrease, which is what you would expect because that's the gas competing directly against the LNG.

Again with the expansion we have the increase here in the expansion and we see that Topock continues to even lose more in terms of its market share into the California market.

We go into the Pacific Northwest with the expansion that occurs here. It has a much greater impact on the Canadian gas, as you can see here. And that's because it's coming Malin, the Canadian gas is coming into Malin. And so what it's doing is basically making the Canadian gas price go down in order to compete with it.

And what we're seeing here is, again we have the Southwest is still down because of the gas coming in to the southern part. And then when we go with the expansion, which is in SoCal, that's the SoCal bit, we're seeing some further decline here in the Southwest gas coming out and the Canadian gas, which is right in here, it's shoved out just a little. It's shoved out right in here because that's when the Pacific Northwest gas starts to come in.

And again it's competing at Malin so really you're having, you're having a substitution here. It's just that the LNG is substituting for Canadian gas and so the Canadian gas is just not flowing in to the California market.

And that's the end of it in terms of talking about the changes we made to the model, the impact it had basically on prices. Our overall demand was not significantly changed. Structurally though the supply sources were significantly changed by reducing the amount of LNG that would be coming into the North American market. We saw the results that you would expect with the higher prices to encourage the gas to be produced in the North American market.

Any questions?

PRESIDING MEMBER PFANNENSTIEL: Commissioner Bohn.

PUC COMMISSIONER BOHN: One possible conclusion it seems to me is that we ought to let a lot more LNG. If you took the limitations of LNG and then just arbitrarily said, okay we'll put in two more LNG regasification plants does the direction of the model continue its same way?

That is to say do the prices continue to come down?

MR. FORE: No they will stabilize because the LNG that we're bringing in basically is the cheapest LNG available. So if we had additional capacity early in the game it would only attract LNG probably at a higher price.

But what limit that would be before it wouldn't bring any more in we're not real sure of. But every time we've run this with the LNG even in previous IEPR sessions we do see a decline of 15 to maybe 50 cents on Mcf over the forecast period when we allow LNG into the California market.

PUC COMMISSIONER BOHN: Does that, do your assumptions include some kind of a world market price for LNG and where do you get that?

MR. FORE: What we did is we used this North American gas model which is Altos. And they have a world gas model. We used the world gas model to really to get what prices LNG can be delivered into the North American market at.

And so it's based on competition throughout the world for that LNG that we have coming in in the original forecast. So basically, yeah, we're using a world model. And it's basically showing all the transportation from LNG liquefaction facilities to regas facilities in Europe and in Asia and throughout the world.

PUC COMMISSIONER BOHN: And so that model includes all the projected demands of China, India and all of that.

MR. FORE: Yes it has been. It's a world model and it has the pipeline flows throughout the world that would be going from Russia into Europe. And that would be competing with LNG as it would be coming into Europe, pipeline flow down into North Africa into southern Europe and the competition it would create.

So it's structurally modeled the whole world in terms of gas flows and gas production centers and demand centers.

PUC COMMISSIONER BOHN: Great, thank you.

PRESIDING MEMBER PFANNENSTIEL: Jim, are we able to see in your sensitivities at what point and this gets actually at Commissioner Bohn's a follow up to his question. At what point the inflow on LNG stops reducing the price overall. How much LNG is lower than the North American price.

MR. FORE: We avoid to put a limitation on the capacity.

PRESIDING MEMBER PFANNENSTIEL: But do you show that in your sensitivities?

MR. FORE: And so if we open, well the sensitivities since they have that limitation, it fills up so technically you would assume more LNG could come in. So what we would do is we'd have to run the model and let the capacity be built.

And in the June month we expanded the sensitivity of the Otay Mesa facility. Well it did fill up immediately so we would assume that the limit we have on it would, if we took it off we'd get more LNG coming but I can't really tell you how much of a difference. It might make another couple of cents rather than any ten or five or fifteen.

PRESIDING MEMBER PFANNENSTIEL: Thanks. Commissioner Geesman.

ASSOCIATE MEMBER GEESMAN: I think you said when you were explaining the limitations you placed on the LNG import capacity in North America that the constraints you assumed was in the liquefaction facilities?

MR. FORE: Well when we looked at Jensen's study what he had indicated that liquefaction was not going to be coming on as fast perhaps as fast as we had originally thought.

And so we decided that the competition from Europe and stuff would probably not allow us to get that 25 Bcf a day of LNG. so we limited that capacity because we didn't it was a good match.

And we didn't rerun the model and go back and take out liquefaction. We just decided to do it at the regas end by just limiting the amount that could come in here.

We didn't limit the flow technically. We just changed the capacity and then the model would tell us whether it would fill. And of course we knew it would since it filled in the June case.

If we would have changed the cost structures at the liquefaction end well then we might have seen a different result in terms of the amount of LNG that would have been delivered at the regas plants here. But the liquefaction end wasn't changed, in other words.

ASSOCIATE MEMBER GEESMAN: So did you change your landed costs of LNG in North America at all?

MR. FORE: It comes down. I don't have that slide. It comes down slightly simply because the demand would be less if it comes in here. But it's still competing in the world market so there's not a, I don't think there's a great deal of change. I'd have to look at the numbers in order to tell you that.

ASSOCIATE MEMBER GEESMAN: It seems to me that you're reducing your imports 40 to 50 percent from where you were in June and importing into what you've now defined as a higher priced market than it would have been in June.

Isn't it logical to assume that your landed costs of LNG would climb to match that

North American market price?
MR. FORE: Technically, yes. When we get to the hub where it comes in, well basically the price is the same for everybody. So they're capturing you might say some rent there because we were expecting the amount coming in. And if our demand is still up there it requires a high flow of.
They're capturing that increase we saw basically for domestic producers in order to bring additional gas to come on board. Their costs are staying the same and our producers' costs are going up. So they're making a little better profit in terms of LNG coming in.
ASSOCIATE MEMBER GEESMAN: On your slide 22 you detailed your infrastructure changes. And I think the way you described that was that these were hardwired into the model, meaning that they required some judgement on your part as to how you made the changes.
With respect to the Baja LNG facility why does it take seven years in your judgement after the facility starts up to increase the capacity by 50 percent?
MR. FORE: The capacity, we hardwired

that in. And originally we had faith on what Sempra had said in some of their permitting. We thought it would come in sooner. But when we had our last workshop in June Sempra kind of indicated they were dragging their feet a little bit on when they would allow that expansion to occur.

They were going to go ahead and permit it. So we decided to slip it. And this part is hardwired. The volume that it flows is determined in the model. But we didn't allow the model to determine when that capacity would expand.

ASSOCIATE MEMBER GEESMAN: Because if you did it would come in a lot earlier than 2015.

MR. FORE: It probably would have. And that's the same thing we did at San Diego. When we look at capacity there's no way that you can probably push all that gas up into the LA market because you're not going to be able to increase the pipeline capacity. So that's why we know they have put in a line to handle that much. They don't expect to increase it.

That basically satisfies the San Diego market. And so we thought, well that's a good way to leave it. As LNG comes in it will basically become the supply to the San Diego market that will push that gas then back up north into the LA market that would normally come down.

ASSOCIATE MEMBER GEESMAN: But if your price assumptions are even remotely accurate wouldn't it be in the interest of state policy to try and accelerate that pipeline up towards Los Angeles?

MR. FORE: If they can do it cheaper that was our real concern. We had a cap for costs in there but we just were concerned that with all the construction problems you could have in getting expanding the line going through a lot of communities and populated areas that it was probably going to be too expensive. And it's a lot cheaper to go around the Horn.

ASSOCIATE MEMBER GEESMAN: So that's what drove you toward the expansion of Line 300?

MR. FORE: Right, because it comes in there. And when it goes in the LA market hasn't grown that much but we've expanded the gas that's coming available to it. It can't go into the LA marker because we didn't expand the demand that much in the model.

And so it's got to go somewhere. So it either would back down and the LNG flows would not be as great in the Costa Azul.

But if it's competitive what it's doing then is going into Line 300. It'll be in PG&E's interest to increase the capacity on that line.

ASSOCIATE MEMBER GEESMAN: And is the timing of that expansion then closely linked to the timing of the Baja facility expansion?

MR. FORE: Yes. If Baja doesn't expand I doubt if Line 300 would need to expand.

ASSOCIATE MEMBER GEESMAN: On the other hand if Baja's expansion were earlier than 2015 you would expect Line 300 to expand earlier than 2016?

MR. FORE: We would expect there would be pressure to expand, yes, earlier than that.

ASSOCIATE MEMBER GEESMAN: Thank you very much.

COMMISSIONER BOYD: I would comment that Commissioner Geesman has touched on the very area that I think Commissioner Byron and myself at the Gas Committee spent a lot of time with the staff as they made decisions about what to hardwire and what assumptions therefore what results might come out of the model.

And I think, as evidenced by the fact

that Commissioner Byron and I are here as the Gas Committee we're anxious to hear other people's reactions to some of these assumptions and some of the results.

But I think the staff did, after lots of consultation, the best that could be done based on what we know. We'd like to know more but we're interested in feedback and anxious to see if any occurred today.

COMMISSIONER BYRON: May I ask a question?

PRESIDING MEMBER PFANNENSTIEL: Go ahead.

COMMISSIONER BYRON: Mr. Fore, I'm going to go back a little bit. Just one question if I may. Back on slide seven where you showed the difference between the two cases that Commissioner Boyd referred to back in June and our current case in August.

I can't quite read the scale. It looks like the demand increase is on the order of one or two percent over that ten year time period.

MR. FORE: That's right. The growth rate is less than one percent differential. So that it does not increase all that much, that's correct.

COMMISSIONER BYRON: But I just wanted to make sure I'm understanding correctly. Then when I go back to your price slide way back on slide four, then it looks to be about a dollar difference in the price of gas.

MR. FORE: And that's because we have to make up for the growth. And we have to make up for about the Bcfs that we lost. We were at like 24 Bcf for the June case for LNG. We're now at 14. So we got to make up 10 Bcf of domestic production. And that's really what drove the price up.

COMMISSIONER BYRON: So am I understanding it correctly? The one or two percent change in demand results in about a 15 to 20 percent change in price?

MR. FORE: Well, no. The demand change, if we ran it and left the LNG the way it was the price would probably not change significantly.

But since we reduced the amount of gas available to satisfy that demand it had to be made up out of North American production.

And the only way it could be made up is if the price was higher. And so that drove the price up.

And if we look on our cost curves we're still in a fairly flat portion of the cost curves at this particular time. So the price increased but as you get further out in terms of the amount of reserves that are being produced in the US we're going to see a much steeper increase in price than when we have a change like that.

But if we look, we did an aggregate of all the costs curves and put them together. We're still in a fairly flat area over the next 10 years. That's why we don't see the price increasing dramatically in terms of bringing on new production.

But when you get to about 2025 if production levels stay where they are gas prices are going to take off based on what we see on the cost curves. They can shift because of technology and things but right now we're still in a fairly flat area in terms of increasing production in North America. But it does require higher price to do it.

COMMISSIONER BYRON: Okay, thank you.

PRESIDING MEMBER PFANNENSTIEL: Tim.

ADVISOR TUTT: Jim I had a question

about the sensitivities. As I understand it sensitivities two, three and four all have the same one billion cubic foot facility in southern California in the first four years.

And yet there seems to be differences particularly in sensitivity four in the price change you get from the base case. Can you explain that?

MR. FORE: Let me get down here so we can look at it. Okay, comparing it to the price decreases we had here we were around seven cents or so in Malin and 15 cents or so there.

And then we're looking at maybe 18. This is 2011 so we're looking at, you know it's a little bit different.

ADVISOR TUTT: And look at Scenario 4.

MR. FORE: What?

ADVISOR TUTT: Look at Scenario 4.

MR. FORE: Okay, and then at four, one day at Pacific Northwest, this is 2011. We have a 30 cent at Topock and I'll have to check that. Because I really can't tell you why it's 15 cents difference on it.

PRESIDING MEMBER PFANNENSTIEL: Thank you, Jim. Lorraine do we need to interrupt for telecomm or are we --

MS. WHITE: Yes we do. If you will just humor us for a few minutes we'll get the call and then we're set.

PRESIDING MEMBER PFANNENSTIEL: I might want to just, I think I saw one question for Jim. And then we'll do the interruption.

MS. WHITE: Great, thank you.

MS. SCOTCHER: Jill Scotcher, PG&E. I was curious about your western Canadian supply assumptions. Do you have climb rate in there. And if so how fast because our modelling exercises suggest quite a bit of sensitivity in the state of California from Canadian decline.

And you have Tar Sands going up but it looks like Canadian imports are fairly constant. So I'm curious about what you have in your model.

MR. FORE: We haven't changed anything on the cost side of it. And so we increased that and as the LNG comes in but we have Canadian staying fairly constant in the thing. I'd have to look at the price but evidently we're not changing the differentials.

It's not changing that much in order to keep that from occurring.

MS. SCOTCHER: So you don't have a decline, a Canadian production decline.

MR. FORE: We did originally.

MS. SCOTCHER: Originally you took it out?

MR. FORE: But when we had the higher price it caused the Canadian price to flatten out.

MS. SCOTCHER: Okay, if I could suggest maybe looking at some of the studies out there that suggest a drop off in the Canadian production.

MR. FORE: Well, yeah we saw, like I said, we saw that in June but then we raised the price. We saw basically Canadian production stayed flat. It didn't really increase but it didn't go down is what happened.

MS. SCOTCHER: Okay.

MR. FORE: Just like we see in California with the increased drilling. We're seeing California gas starting to flatten out for a short period of time. That's what we think is happening in Canada.

MS. SCOTCHER: All right.

COMMISSIONER BOYD: But I think the question is a good question because I think we've agonized over whether we are, whether we really can draw, is there more gas to be drawn down here under any circumstances.

MR. FORE: When we look at production out of western Canada we're seeing a tilt over to start a decline. But we did see it barely starting. So how fast that will occur is somewhat price related.

If the price goes up that will tend to flatten that a little bit. But we do see western Canada production when we plot it over time that it's peaked. And it's starting to come off a little bit. But we didn't see a great deal of drop right now.

COMMISSIONER BOYD: What we don't know is how fast and what kind of incentives there will be for them to divert more of that gas into the Tar Sands operations. And a lot of it depends on the price of oil and how fast they think they can move that oil.

So it is one of the speculative areas.

MR. FORE: Right. And you know and there are new facilities that they are saying need at least $35 a barrel for oil. So when we suspect it might even expand more than we have here.

But probably time-wise it's going to be outside the forecast period whenever they expand that much.

PRESIDING MEMBER PFANNENSTIEL: All right, Lorraine, another question, okay.

MS. WHITE: There's one more. Please come to the mic and speak clearly into it please. For those on the webcast.

DR. BROOKS: Bob Brooks, of RBAC. I have a question about the expansion on Line 300, PG&E. It was curious to me. I didn't really understand when you said it was going to benefit PG&E to do this expansion.

It seems to me that if what you assumed is that demand in southern California isn't going to be increasing very much, I assume in northern California is not going to be increasing very much which basically means that this expansion of 500 a day simply going to be displacing flows on the Redwood path, line 400 and whatever.

MR. FORE: That's probably right. We would show --

DR. BROOKS: And then so I don't see how they're going to increase revenues or how are they going to pay for the expansion? I mean, what benefit does it really have for them?

MR. FORE: Well, of course the model doesn't look at what's good for PG&E. It looks at what's good for California. And it shows a price differential in favor of the south and to move the cheaper gas into the north is going to expand the line.

And so PG&E may not want to expand the line. But in terms of the way the model is run it's going to go get the most economical source of gas for the demand centers. And it is coming up Line 300. And that's why the model would show it expanding.

COMMISSIONER BOYD: But I would agree that that of all the bullets on the infrastructure change chart, that is the most speculative in my opinion.

PRESIDING MEMBER PFANNENSTIEL: Are there other questions? All right, I'm going to hand it back to Lorraine to take a very brief break.

MS. WHITE: Yes, thank you. It will take us just a few moments to bring the call-in line up so it might be the perfect opportunity if anyone needs to stretch their legs. Thank you.

(Off the record.)

MS. WHITE: All right, I'd like to reconvene the workshop. Chairman we do have one individual on the call-in line who would like to ask a question. Eric Wanless from NRDC. So as soon as we get everyone seated then it --

PRESIDING MEMBER PFANNENSTIEL: He wants to ask a question of Jim Fore.

MS. WHITE: Of Jim Fore.

PRESIDING MEMBER PFANNENSTIEL: All right.

MS. WHITE: Or we can --

PRESIDING MEMBER PFANNENSTIEL: We probably need to wait for Jim.

MS. WHITE: Right. Or we can actually wait until the comment period. It's up to you.

PRESIDING MEMBER PFANNENSTIEL: All right, I think because Jim is not here we need to keep moving. So Eric we will hold your question on --

ADVISOR TUTT: He's already here.

PRESIDING MEMBER PFANNENSTIEL: Oh, okay, why don't we take it now then. Eric are you there? Do you want to --

MR. WANLESS: Yeah, this is Eric Wanless

with NRDC. I have a quick question that I guess is a comment in the form of a question.

And my question is in the model or in your thinking about the natural gas forecast and specifically with LNG did you guys take a look at all in terms of how California's Greenhouse Gas Policy might come into play in terms of, I guess, the energy penalty associated with LNG in terms of emissions standards and that sort of thing.

But that's something I can see potentially constraining LNG in the future. And I'm just curious if you guys thought about that at all.

MR. FORE: We have an assumption in there that the LNG comes in will meet the California standards. And so, no, we haven't really, I think what you're looking at in terms of greenhouse gases. We were assuming that if the south coast has some restriction on the gas quality that the LNG will meet that standard in the south coast air district or any place else in the state.

MR. WANLESS: I guess I'm talking more about the energy associated with the compression. I know that at least in the low-carbon fuel standard that's something that people are pretty concerned about in terms of the energy used to compress the natural gas into liquified natural gas and to keep it cool.

That is something that I can see coming up in the future in terms of constraining natural gas imports in the form of LNG into California.

MR. FORE: I'd say no, we haven't. We haven't changed the cost structure of LNG based upon a greenhouse policy that really looks at cradle to grave in terms of moving the LNG to California.

MR. WANLESS: Great, thanks. I just wanted to have that noted out there.

MR. FORE: Okay.

PRESIDING MEMBER PFANNENSTIEL: Thanks, Jim. Now we move to Mike Jaske.

DR. JASKE: Good morning, Commissioners. My name is Mike Jaske with the Energy Commission staff. And what I'm going to do is give a brief overview of the scenario analysis project, particularly focusing on natural gas demand and power generation. And then turn the microphone over to our consultant from Global Energy, Dr. Ann Donnelly who will go through the technical presentation on the work that they have done.

As some of you know the Energy Commission wanted to sort of examine a broader set of analytic approaches and in particular try to come to grips more directly with some policy and strategic options.

So the scenario project itself is an outgrowth of that activity. We decided early on last fall that we needed the capability to develop a whole series of natural gas price forecast as part of that and also to examine the consequences on natural prices of changes in gas demand.

So what I'm going to talk about at an overview level and what Ann Donnelly will present in more detail is focusing much more on the demand side of things as contrasted with Mr. Fore's presentation that mostly focused on supply side and sort of the baseline.

The scenario project itself is trying to understand the consequences of the basic approaches that we're all aware of, trying to drive down greenhouse gases in the electricity sector, evaluate those consequences and sort of understand more clearly what trade offs are.

We've done a whole series of reports and had several workshops already. And as Lorraine indicated earlier we have one more to come after today in September.

We didn't have the ability to bring all this work together in our original documentation of June and so we had three elements of that work that have sort of been trailing along, ageing power plant retirement work that we'll talk about this afternoon.

In particular, aspects of the implications of lower, power-generation, fuel consumption on natural gas prices and some water consumption analysis.

And this morning we'll be focusing on this natural gas market clearing price issue. Just to refresh your memory and for those who haven't been connected to this scenario project before, we constructed and evaluated these nine thematic scenarios, thematic in the sense that they stressed broad strategies to reduce electricity demand and hence the gas burned in power generation, particularly here in California since there's almost no coal or other, in very small amounts of other fuels, high renewables also cause that to happen.

And then in these Case 5s we looked at both high efficiency and high renewables which of course would have greater effect than either of the two alone.

The As and Bs on these cases indicate whether the scenarios were done just for California or westwide. In both instances whether it's an A or a B scenario the analysis looked at the entirety of the western interconnection sometimes colloquially referred to as WECC.

And so it's on a westwide basis, of course, that the greatest absolute value effects happen just because WECC is approximately three times as large as California in terms of all the various indicators of electricity, annual consumption, fuel used et cetera.

This just depicts a little bit about the relationship between the cases. So Case 1 over on the left side of the chart is the most conventional, has the least amount of incremental efficiency or renewables. As and we move up towards the higher numbered cases we have increasing levels of energy efficiency or renewables.

And as Lorraine indicated in her

introductory remarks this morning we are now under way examining yet further energy efficiency scenarios. So we'll be moving sort of off this chart farther to the right from that Case 3A indicator.

We were using a variety of models to do this analysis. We're using products that are supported and used in consulting arrangements by Global Energy. The electricity version of those models, production costs models the Energy Commission staff has used for a number of years.

I believe this is the first time that the gas capabilities that Global Energy has been used in Energy Commission analysis.

And the particular things I'm going to stress in the balance of this presentation focus on the predictions of power generation gas demand as a result of the scenarios that create high levels of energy efficiency on the electric side or high levels of renewables. And then trace through what those consequences are.

This is a bar chart showing the results in a very aggregated way for the nine thematic cases. So there's a bar for each case. This is annual energy generated to serve California load and we're out in 2020. So these scenarios have had the greatest amount of time to unfold.

And so compared to earlier years this would have the greatest impact. If you look at the bar for Case 1 on the far left you'll see that the largest single source of generation is natural gas burned in combined cycles, peakers, old steamers and others still around.

And as you go gradually from left to right you get pretty progressively less amount of natural gas demand, natural gas as the source of generation.

And if you get all the way over to Case 5B you can see just by examining the size of those green bars that that's the lowest level of gas for power generation of any of the scenarios.

This is a chart constructed in the very same way for all of the remainder of WECC. So all the other states, the Baja part of Mexico and Alberta and BC all part of the western interconnection. And again the green bars are electricity generated with natural gas technologies of the various types.

Again there's a progression from the left scenarios towards the right scenarios to have less gas demand but it is a little more irregular depending on the construction of the scenario.

But again as was the case for California, Case 5B has just to the eye, the least amount of natural gas used in power generation.

So this is another way of looking at that very same thing I was drawing your attention to in the bar charts. But here we see the chronological unfolding of the scenarios. And we're looking here at, I apologize, the units are only visible if you turn your head and look at the legend.

This is the volume of gas used in power generation for the totality of the western interconnection. So as was the case in the bar chart format, the orange line at the top is the Case 1 and the most conventional of these cases.

And the line clearly rotates to have lower and lower predicted demand as you get into the cases that have greater and greater penetration of energy efficiency and renewables.

And in Case 5B, as I pointed out before, is noticeably the lowest of any of these.

Now this is the very same chart with one more line added. And it's the black one that's in between orange and blue. So it's the second one from the top. This is the original staff power generation gas demand forecast prepared in the spring, documented in the staff's preliminary assessment report and, of course, modified through the recent work that Jim explained just a moment ago.

And, in fact, this next chart with the pink line shows that new result. It's slightly higher than where it was before as he indicated.

So we effectively have a series of seven lines here on this chart. The four at the top are all versions of what you might think of as baseline views of gas and power generation. From the most conventional being the orange one at the very top and this sort of royal blue one being the fourth one down is our scenario project Case 1B.

It involves the levels of energy efficiency renewables through RPS, some degree of rooftop photovoltaic that is kind of the outcome of current --

The three remaining lines which are either flat or climbing slightly or declining more visibly in the case of Case 5B are the results of the efficiency renewables and combined scenarios where we're evaluating sort at a high level the consequences of very high penetrations of these things. Well beyond the levels of energy efficiency now directed for utilities to pursue or for renewables as well.

And it's these reductions in natural gas demand for power generation as a result of those strategies that we're most focusing on in the project that we had Global Energy conduct for us.

And I think I have basically said that while the chart was on the screen. So our objective then in the particular project that we had Global Energy conduct was to look at what are the consequences of this Case 5B?

It's clearly showing a quite different trajectory of power generation gas demand. It's not a business as usual portrayal of one kind or another. It's a, what if, consequence. And so we wanted to trace through what were likely impacts on natural gas prices if such a scenario were to unfold and play out.

There have been studies looking at this in the past. Lawrence Berkeley Lab produced a report either in late 2005 or 2006 for compiling a variety of these and trying to understand something about the assumptions and techniques that were being used.

So we had Global devise a method to evaluate this and they're here today to talk about their analysis both in for the set up to this particular work and then the particular analysis itself.

So with that I'm going to have Ann Donnelly from Global.

PUC COMMISSIONER BOHN: Let me just ask it. May I ask just one question before you go on.

PRESIDING MEMBER PFANNENSTIEL: John I think you need to speak into the mic or it won't pick up on that.

PUC COMMISSIONER BOHN: May I ask just one question before we get started. I want to be very clear that the task at hand is a relationship evaluation unaffected by and undiscounted by the probability of achievement.

DR. JASKE: That's absolutely correct. I was attempting to be very clear about this. We said, what if we have this kind of energy efficiency and this kind of renewable generation as well as rooftop PV play itself out not only in California where policy makers have some ability to direct that to happen but also throughout the west.

It's, of course, not a novel idea. Western Governors Association sponsored a whole clean and diversified energy analysis consortium to examine that very thing. It reported its results to Western Governors Association. They endorsed a resolution sort of broadly commending states to pursue those actions.

We have the MOU that several states have now joined with California to pursue greenhouse gas reductions on a major scale.

That this, what if scenario is certainly compatible with those efforts. But it is just a, what if, and tracing through the consequences.

At this point at least our friends over at ARB and perhaps in the Legislature will maybe move the ball forward, Ann.

DR. A. DONNELLY: Thank you Mike. Good morning. I'm the project coordinator for the Global Energy Decisions Gas Modelling Project working under the direction of Dr. Jaske and Ruben Tavares. And I have a number of my team members here. And I think I'll just get started.

This first slide shows what I call

natural gas forecast study group. We started this project in December of 2006 having to meet some fairly aggressive deadlines to get done by July and have all of our results reviewed et cetera.

So the structure of this project involved us, the experts responsible for producing the forecast. And I list some of our experts and they are here today. Then the Commission staff who supervised our work and made sure that we were always on target and doing what they needed done. And then we also were very pleased to involve experts from the other consulting groups.

As they had time and they didn't always have time because they had their own projects that they had to get done, but they made some extremely helpful comments. And we thought that the peer review that we got all along the way was extremely valuable. So I want to thank them for taking their time to do that.

We also have someone from our team serving from the extended team and that is Dr. Robert Brooks whom you've already met. And he's the inventor and owner of the gas model that we used, GPCM.

And we wanted him to be here today in

case there's any detailed questions about his model. He can answer them a lot better than we can. So he's been extremely helpful in being very transparent, very open about everything that we've done.

We don't believe in a black box, modeling approach. We've tried to transfer all the technology of what we've been doing with the model to your staff. And he's been very helpful in helping us do that.

So the topics that we're going to cover today, first we're going to summarize the forecast so that we can sort of see where we're going. But it's very important, anything involving gas forecasting to know how you got there.

So the next three topics are going to be some technical topics about the methodology. How the stochastic forecasts are being done. The basics of this model, GPCM. How those results are then integrated with our MarketSym which is our electricity simulation software.

Then we'll actually tell you about the results of the eight forecasts that we did. And most important we're going to tell you about the limitations of the analysis. So we don't get too full of ourselves and too enamored of our results. We have to remember that they are limited by what we did.

And then we have some ideas about some next steps. And I do want to bring up that the very greatest detail about this study is be found in the report appendices which are referred to there. So if anyone either on the internet cannot locate those appendices they should just contact me.

Here's an executive summary of the forecast that we ran. This is the six scenarios. The illustrative base case or what we call our base case and five additional scenarios. A scarcity case and four low-demand scenarios.

So here's our base case. Here's the high-scarcity the high-price, scarce gas case. And here are the low-demand gas cases. So this is the results of our work.

The scarcity prices are approximately four to five dollars per MMBtu higher than our base case. And the low-demand cases are approximately 50 cents to a dollar lower than our base case.

So that kind of gives you an executive

overview. I want to point out the footnote. And we're going to talk more about this. In these early years you'll see a decline or a rather steep decline, I want you to know that Global Energy decisions uses for the first 24 months the very early part of our forecast, we used the NYMEX futures. And these are Henry Hub prices.

So the NYMEX futures prices are very applicable for the specific time period in which we're completing the forecast.

And for these specific forecasts we averaged the NYMEX futures for December 19th through the 21st. And we want you to be aware of the influence of NYMEX futures on the early, very early part of the forecast period. And we have a slide where we show you this. But I just wanted you to see that right from the start.

Here are the actual numbers that were on that graph so that you don't have to wonder what they were. Here they are. We see the base case which we sometimes call the illustrative base case. The illustrative base case, the scarcity case and then the four load demand forecasts. And we're going to go through those.

LDF means load demand forecast, IBC is

something in our base case. And I want to bring out that our base case was selected back in December of 2006. To be Global Energy decisions, December 2006 reference case our corporate-wide, most-likely gas price forecast modified in only one way.

And that was to insert EIAs 2007 crude oil forecast. We wanted to update that. We were in the process of updating our own. We largely agreed with what EIA had done.

And so in order to bring it more into line with our then current thinking we inserted EIA's crude oil forecast. And you'll see that the crude oil input is very important in modelling GPCM.

So I want to tell you right away what our base case consisted of. And we're going to go through how we developed it.

Now we also ran in addition to six scenarios, we also ran and use two stochastic forecasts. And I want to explain about stochastic forecasts.

Here are those two. We show a base case which is the P50 or the most likely. Our base case P75 and P25. This is the low price and the high price.

So I want to explain what stochastic forecasts are if you're not totally familiar with all of this. They are not a different scenario with different inputs. They are simply mathematical results of Monte Carlo simulations around a particular case. And in this case around our base case. So it's not a separate scenario.

And we produced the full range of the stochastic forecast, all the way from P1 to P99. But we just selected and with staff, of course, helping us make the selection.

We selected P25 for a low case and P75 for a high case. Now I'm going to show you how the stochastic forecasts are done. And this is very typical. We tried to make everything that we did completely understandable to the staff.

And we have an appendix H4 which describes this process completely. So the stochastic forecast really don't simulate a completely world view but what they do show is shocks such as hurricane events, pipeline ruptures or the co-occurrence of several of these factors such as we've had in the Rocky Mountains recently where slack demand periods coincides with a pipeline event. You get really low prices.

So, and to do this, to actually produce these stochastic forecasts we use what we call our planning and risk software. We start with the Henry Hub price, in this case our base case.

And we perform what are called stochastic draws based on the daily volatilities. And then we do what's called a mean reversion based on our historical data. And I'm going to show you a slide on volatilities because they're extremely important in all of this.

Then the next step is for the end of each month we averaged daily prices for 500 Monte Carlo iterations. We sort the prices and then the price that's 25 percent from the top becomes our P75. And the one that is 75 percent from the top becomes our P25.

So we constantly update our volatility history. Volatility history is crucial in this price forecasting business. And it's key to not only the stochastics but also our mean reversion processes for the daily volatilities.

For anyone really interested we wanted to let you know that we use a simple time series. In other words we used the last two years of history for the next two years of volatility and mean reversion estimates.

And for our three to four year look we used the last four years, et cetera. So we want you to know as much as possible what we do and why we do it.

And we want to say a little bit more about volatilities. And so I think we'd be very well served if our volatility expert would come up and just give the one minute brief overview. And so this is Lou Barton. And I want you to meet him and hear what he has to say on this very important topic of volatilities.

MR. BARTON: All right maybe it'll take more than one minute. But the volatilities were calculated by taking day-to-day percentage changes and then turning the standard deviation over the set of data over a certain period of time. And we're showing 90 day volatilities here.

The shorter terms would give very useful information but it wound up being spikier and spikier. But this kind of shows an array of things that affect gas prices.

And it could be demand. It could be hot weather in the summer or cold weather in the winter. It doesn't show here but nuclear outages can cause gas price spikes because natural gas plants are usually on the margin and there would be a jump up in gas demand.

NOx and SOx prices can affect gas demand. And couldn't fit it in over here but last summer there was a price drop which caused price volatility to go up.

We had a lot of LNG coming in at the same time that NOx and SOx prices were dropping. So you had coal plants and oil-fired plants displacing some gas. Let's see, storage levels if you come out of a winter you had high storages as well over here. I think the bottom here was like $3.80.

Recently coming out of this winter we had a cold spell. And you're well aware of various hurricanes here in the past. But the use of volatility our percentage curve a day for one standard deviation. So that means let's say here nine percent here that's one standard deviation so two standard deviations would be 18 percent. And if you remember the bell-shaped curve two standard deviations would be about 68 percent of all the next day prices.

So for example a $6 gas price and you have say a five percent volatility, that means I can say that I am 68 percent confident that gas prices tomorrow will be between $5.70 and $6.30.

The practical impact of all these volatilities is it makes option prices very expensive. If buying a ceiling price on natural gas which would be a call option winds up extremely expensive. It would be just like trying to get a life insurance policy on an 80 year old.

If you want to buy $100,000 life insurance policy that policy may cost $75,000. So it makes it very impractical when volatilities are high.

However this flat trend line here as you can see there hasn't been much of a change over the last 15 years as to volatility.

ASSOCIATE MEMBER GEESMAN: I have a question. In light of that volatility and I think that your comment below the graph is pretty instructive, you're showing 90 day volatilities and if you were in a shorter term it would be even spikier.

In light of that, why in your use of NYMEX for the first two years of the Global forecast do you choose just to take the most recent three days. Doesn't that put an extraordinary amount of volatility into the front end of your price forecast?

MR. BARTON: Well.

DR. A. DONNELLY: I think I'll take that. That's one of the reasons we average over three days. We certainly wouldn't want to take a particular, one particular day. We average over three days.

And it's the way that we measure the fact that at the time that we're doing the forecast gas prices basically are set. And they are set by the NYMEX futures market.

Of course we'd like to average over a really long time. So we select three days as a good measure of capturing at that particular time where the futures market is. And, of course, it changes constantly.

So that's why I mention it. There is not as much utility to those first 24 months of our forecast as there is to the remainder. But we have many clients who are active every single day in the NYMEX market. And they know that that's what prices are.

ASSOCIATE MEMBER GEESMAN: So do you publish a new forecast every day?

DR. A. DONNELLY: No, we don't publish a new forecast every day. We publish a new, we have a monthly forecast and we update our reference case every six months. So everyone, we make this totally clear to everyone that that's what's in the first part of our forecast. And they would be wise to replace it everyday with the next NYMEX futures.

So that's why I bring it up and you made quite a point of it. But the NYMEX futures market is now so very influential in establishing what gas prices are that recently just take it for the first 24 months.

After 24 months there's not enough liquidity in the NYMEX futures market to really have it become any kind of standard. So it --

ASSOCIATE MEMBER GEESMAN: I certainly agree with that latter point. I guess the concern I have and I appreciate the caveat you put on it.

DR. A. DONNELLY: Yes.

ASSOCIATE MEMBER GEESMAN: And I think it's appropriate to make that caveat. From our standpoint, government agencies don't always listen to those kinds of caveats. And we move extraordinarily slowly.

DR. A. DONNELLY: Yes.

ASSOCIATE MEMBER GEESMAN: So the way we're likely to use your forecast for decision making, setting, for example, the market price referent that governs what prices utilities are required to pay for renewable contracts.

We'll take that snapshot based on three days in December of 2006 and probably use it for a full year with no adjustment, no recognition of the caveat that you've expressed. And I just think that when you're around us you need to be very apprehensive about that propensity to misuse your work.

DR. A. DONNELLY: Yes. Well that's very, that's very good advice. And one of the reasons that we wanted to bring it right up front. And with our reference case the client always has the option of inserting their own view of things into GPCM or our reference case.

And that's why we always want to make our assumptions totally clear. This particular approach works for the vast majority of our clients who are very attuned to them.

NYMEX futures market, well we understand it's not ideal for everyone. So we always are eager to customize our forecasts for the particular needs of the client.

In this case our actual forecast period was 2009 to 2020. So it was out of the NYMEX period. But I really want you to know everything about how we do stuff. Because that's the way to really approach gas forecasting.

So anyway, the interesting thing is that volatilities despite all the headlines has not really increased in recent years. It just seems that way.

Another question is, is the history of volatility really the best predictor of the future? And we understand its limitations but it remains, historical volatility remains the best available source of quantitative analysis that we have available to us.

But of course it's a limitation. So I think we should probably go on unless there's more questions.

Now we go to the topic of GPCM. Which is the model that we use and that we licensed, We licensed this from Bob Brooks' company. He's the inventor. And we use it to produce our natural gas reference case for North America. We make changes representing our world view. And it's a flexible tool that we can use.

And so we wanted to make you aware of some of the fundamental principles of GPCM. And really there are four that Bob emphasizes in all of his handouts and that we want to emphasize as well. Here are the fundamental principles: That markets are competitive. Prices will rise or fall to clear the markets. Gas will flow from production to consumption regions so as to minimize transportation and storage costs while clearing markets. And the resulting set of flows constitutes an economic equilibrium for the natural gas industry. So this is an economic equilibrium model.

The supply model has 107 existing and potential supply sources and that would include US production, Canadian production, LNG regasification facilities, Mexican production, for a total of 107 different supply sources.

One of the things that is really important to understand is how are different tranches of gas accounted for in different models.

And we found that these equilibrium models have a lot in common but you have to be very careful in understanding exactly how the accounting goes before making direct comparisons.

And one of the examples that we found very noted was that Alaska North Slope gas when it comes in in GPCM comes in as an import from Canada. Because what will actually happen is Alaska North Slope gas when it does occur will flow into Canada, be used to satisfy Canadian demand partly and then the excess will flow to the US. So that's how it's accounted for in GPCM.

In EIA their model accounts for Alaska North Slope gas as a purely US production source. So this is where it is really important to understand exactly the inner workings of these models before trying to make a line by line comparison and saying wow, something doesn't match up here. If it doesn't it is likely to be because their categorization is different.

So it's really important also to understand what's an input and what's an output and I have just listed them here. I am not going to go through them totally in detail but the inputs are things like supply regions, customers demand regions, pipeline zones, pipeline tariffs, et cetera.

Another really important input is crude oil forecasts and the ratio of crude oil price to gas price. And that is I think something that we need to bring forward because you'll see what we assume is a crude oil forecast.

There is a rather elastic and rather changeable relationship but still rather a fundamental relationship between oil price and gas price. And that's reflected in GPCM.

The output, you'll see some of the outputs there. There are things like spot market prices, market clearing prices, the gas supply available, deliveries by pipelines, et cetera. So you can't make an input and output. You can't say well I think the price is going to be $8, I'm going to put that into GPCM and see what happens. Price is an output. So that's important.

So one of the things we emphasize throughout this project is that we don't believe in, as I think I said, a black box approach in modeling. So all of the features of this model we made transparent to the study group and they were made transparent to us by Robert Brooks and

Associates. So I think that's been one of the strengths of what we've done. Because the more we can transfer to your staff the better.

Now I think we would be well served to have Gurinder Goel and Mike Donnelly get into the heart of the gas supply methodology. And Gurinder is the person who has actually run, done the actual modeling. When we say Global Energy performed these forecasts it's actually Gurinder doing it. So I'm pleased to bring him here.

And then Dr. Mike Donnelly, an upstream authority from the exploration and production business. And they're going to go through two slides. And again a sort of one minute approach to each one because we want you to understand something about how gas supply is handled in GPCM. So Gurinder, thank you very much.

MR. GOEL: Thanks Ann. Hello everyone. Me and Mike will go over the heart of GPCM. How price is determined in GPCM. It's like we are going to do the heart surgery right now so it's going to be more than one minute.

As Ann said we have 107 supply basins in GPCM. Of that 107, 70 are North American supply basins. Fifty-five of them are in US, 13 in

Canada and 2 in Mexico.

And what she said, that 37 are at LNG supply basins but that number can vary. It's not a static number. We can add or remove LNG terminals. And as we remove or add LNG terminals that number will change. So it can be 30, it be 40, it can be 50. As we perceive what is going to be the supply of LNG coming into US to satisfy the domestic demand that number will change.

I will go over what the heart of GPCM model does and Mike will go over how it does it.

GPCM has a proprietary upstream model which gives us a Q Medium quantity which will be available to satisfy domestic gas.

And then what we do is we take a statistical model equation in which we calculate wellhead gas price based on the WDI for the Lower 48. And we tie that wellhead gas price to each of these producing basins based on prior year price. So we get a QMed and Q price. No. PMed and QMed for each of these supply basins. And from these QMeds and PMeds we calculate the high and the low price and quantity for all these basins. And we determine the supply price cost for all of these basins. Which Mike will explain in the following slide how we do it.

DR. A. DONNELLY: We are not actually going to go through all of this but we do want to emphasize that we believe in really understanding the models that we use and in passing that knowledge on to our clients. So Mike is primarily responsible for working with Dr. Robert Brooks to put this into really a graph for you to understand how this important relationship between volume and price is done in this model.

DR. M. DONNELLY: Thank you Ann. Let me just draw your immediate attention to two important factors, one in the upper left part of the screen, it is the volume considerations. Which actually projects the shape of the basinal production declines. That was one of two very important issues that the Berkeley Lab report of '05 pointed out as the two fundamental errors -- areas. Perhaps was a slip there. But two fundamental areas that needed generally more rigorous assessment in all the models that they studied, some 20 supply/demand equilibrium models.

The second point is in the lower right hand side of that graph, which are the supply elasticity factors, which are essentially assumptions. They are empirical estimates of the relationship between price and supply availability. Supply availability and price.

So this model addresses both of those in a step-by function. And those are the two areas that need to be really, quite frankly, rigorously assessed between competing or different models used.

The upstream model is a proprietary model that the Brooks company has licensed and is really is a volume model. It, as I said, predicts the volume availability for these 107 different supply sources based on decline curves, all the hard engineering. I don't want to go into the geotechnical aspects but can certainly do that later.

But it's a rigorous assessment of the petrotechnical and the engineering aspects of reservoir performance. The different declines. Exponential height for conventional gas reservoirs and hyperbolic for unconventional reservoirs, which you heard today mentioned, the tight. The tight reservoirs, the shale and the coalbed methane. They're treated separately and rigorously in that upstream model.

That upstream model produces a base or median quantity, which Gurinder mentioned earlier. It's referred to as the PMed, the quantity Median, the median value.

So as you flow down. As you flow down this curve you have now established your PMed. You flow across here. And this equation establishes the P price. It establishes the median price that will be coupled with that median volume. And as you'll notice the mathematics here are set by the ratio of wellhead gas to WTI or crude oil, Oklahoma crude oil pricing.

That relationship that was derived by Bob Brooks is a very sound mathematical relationship. We are very comfortable with it. And I might say that there was a recent article published in February of this year by the Dallas Reserve Bank that rigorously looked at, and maybe the best I've seen to date, on the empirical relationship and the mathematical relationship between oil linkage and gas price linkage.

And there has been a lot of concern and a lot of analytical work done both supporting and discrediting the linkage between oil prices and gas prices. But this most recent analytical and very rigorous assessment took -- what it did was take out the volatility, the short-term volatility from that linkage. That is extreme weather, storage inventories, pipeline disruptions, supply disruptions and so forth and looked at the removal of those short term volatilities. And that the linkage provides a very --

And they used what was called an errors correction modeling. and it showed a very linear continuum of prices where both gas and oil products could be substituted. So it was a very fine confirmation of Bob Brooks' mathematics.

PRESIDING MEMBER PFANNENSTIEL: I'm sorry, who did that analysis?

DR. M. DONNELLY: The Dallas Reserve Bank.

PRESIDING MEMBER PFANNENSTIEL: Thanks.

DR. M. DONNELLY: Or the Reserve Bank -- The Federal Reserve Bank of Dallas. It was a February of '07 study. And we can provide you with a copy of that if you'd like.

The base quantity and the base price then flows into the first point on a three point supply availability curve. That's not a cost supply curve, it's a price availability curve.

Volume and price are established up here and the costs are embedded implicitly in this upstream model based on historical economic limits. In a reservoir an economic limit is reached when the price for the -- the then current price for the commodity equals the cost to produce it.

So all these upstream studies have an embedded or an implicit economic limit to them and that historical limit is forecasted forward. So this is a price curve, not a cost curve, and we need to make sure you're comfortable with that distinction.

You take this first point on a three point cost curve and you then generate and establish the price for your low price and your high price. And these are inputs. You can put any number in here you want. Statistically over the last five years 50 percent of the base price are 200, it could be 225 today, of the P price establishes the high price.

With high and low prices you can go back to this exponential function and that establishes the quantity for low quantity or high quantity. And you can see there is an exponentiation operator here, which is the second-most assumption in any of these models that generates the price elasticity. It is the price elasticity factor. That will then generate the relationship between volume and pricing. You will create the -- You calculate the low quantity and the high quantity.

And there is an empirical check relationship where you can actually calculate or back calculate or start with your assumed empirical estimates. In this model there are annual estimates for every one of these 107 supply basins. For every year there's a high and a low elasticity factor. And that is one of the key areas of assumptions in these models that need to be looked at rigorously. As well as these supply decline curves.

So now you've got your three points on the supply availability curve. High price associated with high volume, low price with low volume and the medium price and medium volume. And you do this for all 107 supply basins for every year.

Now the work done by the Reserve Bank did it on a weekly, not annual basis. And they did it on wellhead gas prices -- On Henry Hub not wellhead gas prices as in this model. And the results were absolutely, phenomenally consistent, mathematically and end results.

So I will conclude with this. And we certainly can take more time to review the logic of this approach. And it is also described in our appendix.

DR. A. DONNELLY: Thank you Mike and Gurinder. So we are very committed to understanding every bit of our model that we use and passing it on to you.

Now just a little bit more about how GPCM organizes data. It uses US census regions and divisions to aggregate the gas consumption. It can also aggregate by state. So there we are in the west, Pacific and Mountain.

Here is an example of a census region and the producing basins that supply it. So you see on the right all the different sources of gas that feed the Pacific Demand Region. And 12 producing basins supply 90 percent of the demand. That is just an example and they are one for each census region.

Here is an example of a particular supply basin and I picked Wyoming Southern. And how it supplies WECC and what percentage of supply coming from this area goes to WECC. The census regions can't directly be aggregated by Reliability Council in GPCM but WECC is approximately equal to Pacific and Mountain census regions. So that's just an example.

Now I know you'll be interested to understand how is LNG treated in GPCM. So here is a discussion that I hope will make that explicit. Each LNG import facility is treated as a supply source.

LNG is structured -- this really gets to some of the questions on LNG pricing that you were asking. It is structured as an incremental supply for shortfall of indigenous production. LNG is a price taker with an infra-marginal price. That means it is going to be priced slightly under the marginal indigenous price.

And in GPCM there are two ways that LNG price is set. There is a floor price which is set at recovery of marginal costs of regasified LNG from 23 plants. So that's the floor.

Then winter prices, there's the other component which would be winter prices that reflect international competition in Europe and Asia. Which has already been brought forth as an important aspect.

GPCM does not utilize a global LNG competition model. I.e., it assumes that LNG is going to flow as long as the model needs more gas to satisfy North American demand to reach the equilibrium solution of supply equaling demand. So it flows in when needed.

Unlike our early hopes maybe 10 or 15 years ago when we were all hoping that LNG would flood the market and give us very low prices for gas, that isn't what we now learn is happening. And we now know that LNG will not flood the market and dramatically lower our gas prices but will come in right underneath our market prices. And this is because of international competition for that LNG and the emergence we think of an LNG exporters cartel-like organization, which will not allow its product to come in and flood the market.

So those are the assumptions about LNG and how it's treated in GPCM.

Then we have to let you know something about, and I'm going to go over very quickly this slide because Mike Jaske has already set the stage for this. This is how our outputs from our gas modeling got integrated into the MarketSym IEPR cases. So on the left we show the IEPR case and the description, which you're quite familiar with, and then our forecast. Our GPCM forecast and what was used in each case.

So for each GPCM gas forecast the Global Energy Market Analytics team would hand us off the electricity generation demand piece for us to use. And only in two cases they were so significant that we looped back and did an IEPR electricity case for that and that's Cases 3C and 5B+. And we'll get to those.

So our Market Analytics software is integrated in a very careful, systematic and very transparent way with our GPCM model. So this is just showing, on the left is the price point for MarketSym and on the right is the same, similar GPCM market point so that we can integrate them back and forth.

This is how Market Analytics displays and adds the so-called basis differentials and transportation costs for each market center. So just more about how we integrate these two modeling approaches.

Now we get to the methodology and the results of the actual forecasts. We produced eight separate gas forecasts. We produced our base case. We produced and used two stochastic forecasts, the P25 and the P75. We produced a sustained scarcity case, a high priced gas case. And then we produced four low demand cases based upon either high energy efficiency, high renewables or both being aggressively pursued in the West.

So we're going to focus on the base case, the sustained scarcity and the 5B+ forecast, just in light of limited time.

Developing the base case. At this point we have to be very realistic about the numbers we come up with in any gas forecast. There are inherent uncertainties. I'm not going to go through all of them but I just want everyone to be aware.

And we all have to make ourselves aware that when we start talking about a gas price forecast it's an uncertain thing subject to all the uncertainties that I mentioned here such as the producing basins that are constantly undergoing changes. Market hubs have different things happening at them, consumption is changing.

And then I want to bring up this last

one. The influence of speculators. And this is something that we don't really understand completely at this point. I think there are a number of studies being run by government and academic sources as to just what is the influence of speculators on gas prices.

And we recognize there is probably an increasing influence but exactly what is it. Some of the studies claim that they are increasing volatility. Others claim that they are increasing liquidity and therefore dampening volatility. So we are not really sure but it is something that we need to be increasingly aware of because the volatility in the gas market attracts risk takers, as we've seen. And we need to really keep up with these studies.

The optimum approach to this whole problem of the uncertainess of gas forecasts is to incorporate scenarios, stochastic analysis and frequent updates, which we do.

This is just to show the different gas demand for electricity generation and how that differs in our base case versus the EIA. EIA is here. Here is GPCM, actually the Bob Brooks and Associates case, and then our case. Our base case uses the demand assumptions from our fall 2006 Market Analytics power base case. So we're consistent with using our own electricity demand.

And we show gas demand for electricity generation higher than either Robert Brooks and Associates considers it or the EIA considers it. So I want you to be aware that different forecasts are going to have different assumptions and parameters. And here is one that I just want to point out right away.

Now for the core load in the industrial gas load. Our base case that we used is very, very similar, virtually identical to the demand assumptions in GPCM and EIA.

Now here is the slide that shows about we incorporate the influence of NYMEX futures in the first two years of the forecast. And maybe we've talked enough about it but again, refer to this slide if you want to understand exactly what's happening.

Here is a forecast, here are the first two years. That's entirely NYMEX. Then we do a mean reversion into a fundamental forecast. And this mean reversion is based upon the volatilities that Lou talked about. So we just really want to be up front with that. And we're always more than happy to meet the needs of our clients by substituting something else. The time period we were dealing with in this study was 2009 to 2020.

Now here is our base case or the illustrative base case. And we want to show how it differs from two different cases. One is EIA, and here is their forecast that they were putting out about the same time that we were selecting our base case. Here is our base case. And here was our old forecast from just three or four months before. So obviously our prices have gone up. And our base case is not all that different from EIA's.

Here is a comparison of some features between EIA 2007 and the base case we selected for your project. We used the same crude oil forecast. We project, our base case projects somewhat higher US gas consumption by 2020 than EIA does. Primarily because of gas used to generate electricity.

And EIA projects LNG imports considerably below our base case. And that's because they project higher indigenous gas production. They are much more optimistic about the ability of the US industry to keep producing more and more gas, particularly in the Gulf Coast, than our base case would show.

All of these prices are Henry Hub prices. I want to just speak very, very briefly about basis differentials. They are very important. We haven't really focused on them in this study because we had to be very focused on what needed to be accomplished, which was Henry Hub forecasts. But basis differentials are very important in setting the option prices.

And the fixed prices that gas suppliers actually give to their customers are very much set by basis differentials and the optionality and the volatility around them. They also are very important in determining what pipeline expansions are going to be built. Because before expanding the transporters are going to study basis differentials and project them in order to see whether it makes sense to build their new pipeline. So they're very important.

I've enclosed some data for two points, Malin and Topock. And I think we have not made much of a study and I won't say much except to say that there is a vast amount of material that we generated in all of these scenarios and forecasts that could be put to use to show what happens to basis differentials as we apply these different demand assumptions.

Now just referring back to all those uncertainties that I mentioned. In order to address these we do constant updates and so I just wanted to go through a few of the changes that get incorporated. And you heard from your own staff the changes that are being incorporated in your reference case.

Similar to us, and I won't go through all of them except to say for example for the base case that we used, the so-called CEC base case, the only thing that we did to our reference case was to insert EIA's crude oil forecast. Very important input to GPCM.

When we got to the spring of 2007 when Global Energy redid our reference case we also added a new crude oil forecast. We brought in less LNG due to global price competition. So we're in somewhat agreement with what you've heard from your own staff. Less LNG. We incorporated a green premium where there is a global push for cleaner fuels, and we delayed Alaska North Slope gas and Mackenzie Delta gas.

And our forecast that is coming up in just a month or two is going to feature more natural gas demand, believe it or not, primarily for ethanol production. Canadian Tar Sands is going to have a new crude oil forecast. And further delay in the Alaska North Slope and Mackenzie Delta.

ASSOCIATE MEMBER GEESMAN: Could you elaborate a little more on the methodology used for this green premium.

DR. A. DONNELLY: I actually am not the best one to do that. You're involved. Can you elucidate on that or Gurinder.

MR. GOEL: For green premium actually we just assume that our optimistic scenario of LNG coming into US won't be that optimistic. Because Europeans, because of the Kyoto carbon standards coming, mandated in 2010/2012 period, that they will consume more natural gas to meet those standards. And we will have less LNG coming in, which will basically push up the prices from our '06 forecast. And that will constitute a premium in our prices.

ASSOCIATE MEMBER GEESMAN: So in essence

it's just another rationale for your assumption of reduced LNG coming into North America?

MR. GOEL: Yes.

ASSOCIATE MEMBER GEESMAN: Thank you.

PRESIDING MEMBER PFANNENSTIEL: Commissioner Bohn, you had a question?

PUC COMMISSIONER BOHN: No, that was my question.

DR. A. DONNELLY: I did want to include our crude oil forecast that was used in the base case. So here is the crude oil forecast. It's basically EIA's crude oil forecast from it's early release of it's 2007 outlook. And also important is the ratio you assume between crude oil and natural gas. And here are the ratios that were used. So I wanted you to know what those were. And those are key inputs into GPCM.

Now we actually get to our specific forecasts, scenarios away from the base case. I'll say a few words about the sustained scarcity forecast because it turns out that this one is really, I feel, quite important. The characteristics that we modeled were indigenous US production drops sharply. And it was by about 35 percent in comparison to the base case by 2020.

We assumed no Arctic North Slope or Mackenzie Delta gas until 2020. We assumed that oil prices would remain really high in the $75 to $85 range. And that we would have high utilization rates for LNG facilities pushing LNG prices up.

And so here are the results for 2010, 2015 and 2020. For example in 2015 our base case is right around $6 and our scarcity case is above $10. So it makes a really big difference. And I'm really glad that we ran this case because some of these things are moving in that direction, the problems with the arctic gas getting down to market. And it's really important to run these alternative forecasts to make sure you're covered for all the eventualities that can happen.

But now we get to the most important part of what we did, it's the low demand forecasts. And so we ran four different GPCM cases that correspond with the same name for the IEPR cases, 3B, 3C, 5B and 5B+.

Now the first three on that list were incomplete in one important respect. They didn't include any modeling of something we consider quite important. And that is the response that would happen in the production industry when demand drops and price drops. They are going to limit production. They don't want a supply bubble, they don't want to create a supply bubble when demand drops in a sustained way.

So our case 5B+ fills in this final piece to the puzzle to make what we consider to be what we consider to be a very significant statement about what happens when gas demand decreases because it's mandated that we're going to be using renewables and energy efficiency more aggressively.

It's important to understand GPCM does not include an automatic loop-back that would automatically do this but it includes the capability and the flexibility to allow us to do it manually and to let us do it in a better and more intelligent way. And so that's what we did in Forecast 5B+.

Here are the results. Actually this is demand for electricity generation in all of these low demand cases. Here is our base case and then the low demand cases. And then just to remind you what the cases were. And again this is 3B, 3C and 5C, do not include modeling of this important production curtailment that the industry would undoubtedly carry out.

Here is the same, basically -- Well here is the price drop from these three cases. And you get a very, a pretty substantial price drop. It clearly demonstrates that lower demand impacted gas prices but we wanted to really make the quantification better so we wanted to model the realistic production capacity response. And we observed that. We lived through the gas bubble and we observed it happening. So we feel quite confident that something like this would occur.

So now we go to this final scenario, 5B+, which does simulate a production curtailment response. And the characteristics were that we took it WECC-wide. We focused on production basins that were the most important in supplying WECC just to simplify and make it a little bit more cost effective. We modeled the response according to observable exploration production industry behavior.

And keep in mind there are several of us who are at the PhD level in geology and have extensive experience in exploration and production, drilling, you know, that type of thing. So we applied our industry experience to this and we shaped the curtailment to what we considered to be the most realistic response. Some production is not curtailed because it is associated with oil production so it is not going to be curtailed.

Then there is another tranche that is unconventional gas resource that you can't curtail without permanent reservoir damage. Then there is another tranche that is not curtailed because small to mid-sized independents who constitute a really important part of our industry, they must produce to service debt and avoid competitive drainage.

And then we also recognize that the industry wouldn't immediately begin doing this so we modeled in a three year lag. Because they are optimists. They think, these low prices, they're going to go away. But eventually they recognize it's sustained so after three years they begin this curtailment. And there's two kinds, curtailment of exploring for new fiends and then curtailing their actual production. So we considered both those kinds. And Appendix H-5 describes all this in great detail.

So here are the results of 5B+. And this shows the supply curtailment. The demand volumes in WECC are reduced and how they're reduced, versus the base case in 5B. So you can see -- Let's get to the --

Here is basically the same result. Here is the lagged curtailment. Here is the drop in total WECC demand. And here is the percentage drop in total WECC supply to total WECC demand. So we basically were modeling those basins that were most important to WECC, California Onshore, Colorado Northeast, et cetera, as listed here. So by 2020 there was a 17 percent drop in total WECC supply to total WECC demand. And as I said before, we modeled a lag, a three year lag, which we felt would be very realistic to what the industry would do.

So here are the results. And you can see 5B+ is gray, 5B is the orange. And this is -- Remember that 5B is the aggressive use of renewables and energy efficiency throughout WECC. So you can see that this production curtailment moderates that to some extent.

But what it shows to me is that it demonstrates the impact of lower demand from aggressive of EE and renewables, even when the industry responds with production curtailment. And as we've seen the industry cannot curtail everything, they must keep some supplies flowing. So I think that's pretty significant.

So now here is the bottom line of what we found. And I want to emphasize, according to this modeling exercise, I mean, we're not proving this by any means, okay. According to this modeling exercise the production curtailment response to adjust to lower demand will lessen the price decrease from roughly -$1 to roughly -$.77. But you still --

So here the results of 5B+ is that you get a decrease versus our base case of 77 cents. Whereas when you don't model this production response you get a reduction of about $1. So that's pretty significant versus the base case. It's 20 percent if you don't model the reduction response and 15 percent if you do. So you still have a fairly significant response.

And we found that very intriguing. Not completely confidence building at this stage. But when we observed recently the Lawrence Livermore -- Lawrence Berkeley Lab report we felt that we what we were doing to some extent corroborated what they had done. And we'll discuss that when we have had more of an opportunity to look at them.

Before we start dancing and prancing and spending all this money, the 77 cents or whatever, we really want to emphasize the limitations of our analysis. And it has been disciplined. It has been step-by-step, it has had peer review and all that sort of thing. It used the best available modeling. But it still has these limitations so we have to remind ourselves that we can't rely on every single penny and that there is uncertainty around it.

Most particularly that in the time period that we selected the base case, December 2006, GPCM has been updated twice. Bob Brooks' company updates quarterly. We've updated once. So a lot has happened. The Alaska North Slope has been delayed, all these important things have happened. Crude oil prices changed and the ratios have changed. New infrastructure has been announced or cancelled.

So there is a lot of uncertainty around the specific results of what we found out. But when we look at it we feel that it's at least a credible foundation to go forward and improve on this quantification on this important point of what will happen if aggressively using EE and renewables, will this really reduce gas prices. And I think that we have a credible foundation to go forward and further quantify this.

So I think that's logical follow-up work. I won't go through all of these things but we feel that one obvious thing to do is to review the Lawrence Berkeley results in detail. We feel with an early review that yes, there is a lot of corroboration. But we want to look carefully at that. We want to look at the need for LNG.

What would happen if we got drought or a nuclear outage at the same time that we're getting gas scarcity. a lot of unanswered questions. We have answered some but we've asked probably more than we have answered. So I think that's the end of our prepared discussion and we'll be happy to take questions.

PRESIDING MEMBER PFANNENSTIEL: Thank you very much. Questions? I think we've asked them as we've gone along.

DR. A. DONNELLY: Yes.

PRESIDING MEMBER PFANNENSTIEL: Questions from the audience?

MR. FORE: I'm Jim Fore with the CEC. The question I have is on the substitutability, which I guess is your area. We look at this and, you know, every time we do a forecast it's how much substitutability exists. And the way we're set up, there is no substitutability in the residential/commercial sector so it only leaves the industrial and the electrical sector.

In California we have no substitutability capability other than two plants and we're seeing this spread throughout North America we think. And with the Kyoto Agreement we see it maybe in Canada and even in Europe. And, you know, you have substitutability in yours. Is it based on history or is it based on the outlook of what substitutability will take effect or can be effected in the future?

DR. A. DONNELLY: You're referring to fuel switching, fuel switchability?

MR. FORE: Between the oil and gas.

DR. A. DONNELLY: And so the relationship between the crude oil price and the gas price.

MR. FORE: And the gas price.

DR. A. DONNELLY: Okay.

MR. FORE: What we're seeing, we're feeling it's becoming more and more disengaged, simply because the regulations will not allow the substitutability. So, you know, we're wondering if you're basing it on history if you're being too optimistic because we're seeing less and less impact of crude prices on our gas demand.

DR. A. DONNELLY: Well I'm going to let Mike answer but I want to point out that there are a number of large, large customers throughout the Midwest and East who still have some. Obviously it's diminishing but they still have some substitutability. And so that's something to bring forth, that in California you probably have less than in most areas.

And since it's a full global market, or certainly a North American market, what happens throughout the big market areas in the Midwest and East have, do have a bearing on what happens.

MR. FORE: But I'm curious though about, you know, what percentage of the market is that impacting in terms of gas demands. Is it causing it to, you know, jump up how much in one month if they substitute and stuff. Is it enough to really impact the price over the long run.

DR. M. DONNELLY: Again I think we're looking at our forecasting as more on an annual basis. But as I mentioned, this issue of the Reserve study that was done by the Reserve Bank of Dallas looked at it on a weekly basis. So they have a much more rigorous assessment but very comparable results.

But the switchability between fuel oils and gas is diminishing. And I believe the last numbers that I looked at were something like 5 Bcf a day in about a 50 Bcf market total. So you had maybe ten percent or thereabouts on an annual basis to substitute between fuel oil and natural gas. But that is a diminishing factor.

What was so interesting about the, not just Bob Brooks' mathematical relationship but also this Reserve study, was that it took out -- it was independent of that switchability. It looked at the historical price relationships with the volatility of gas prices removed.

That is short-term disruptions in supply, pipeline deliverability, inventory flexibility. It took out seasonality of pricing and demonstrated a very close continuum of pricing. So you could either substitute gas or oil products pricing. It was based --

Again, are you asking me to explain why there is a mathematical relationship or correlation, an R-2-squared factor, it's very strong. Why, historically it was probably based largely on oil substitution. Going forward it is probably largely based on LNG displacements or availability of LNG, which is largely linked to crude oil prices. It varies from market to market. And quite frankly we haven't discussed it very much today but on the utilization of coal. Does natural gas displace coal?

One of the reasons our demand forecast for the power sector is quite low, lower -- higher I mean. Our utilization of gas for power generation is quite higher than for instance EIA. EIA has significantly more coal generation in their forecast. We most recently put a carbon, we estimated the carbon tax impact. I think it was \$2 up to \$12 a ton equivalent, a ton of CO2 equivalent. And we see a diminishment of coal value whereas other forecasters do not see that.

But I think that going into the future

that linkage is apparently holding as of '06. If you look from '06 to '94, between 1994 and 2006 there is a very strong correlation between natural gas prices and oil if you remove oil price volatility factors.

Now again, it's hard for me to say why that should be projected into the future. I don't believe it is substantially related, even in the past to this ten percent of gas demand switchability on an annual basis. But your point is well taken. I think that whatever that basis was for that prior correlation it will be diminished in the future. But being replaced by LNG and the ability of gas to displace coal.

MR. FORE: Thank you, that's one we wrestle with it every time we do a forecast.

DR. M. DONNELLY: It's a very important question.

MR. FORE: You know, whether we want to consider it or if it's fading out, you know. And particularly now that we're going to the world market in LNG because LNG pricing in a lot of the markets is based on oil price.

DR. M. DONNELLY: Exactly.

MR. FORE: So it's correlated by

contract, not necessarily by substitutability.

DR. M. DONNELLY: And I might point out too that we hear a lot about our world model LNG, which we have. Keep in mind that those models, just like the electric dispatch models, are based on spot gas prices. Somewhere between 10 and 12 percent of global LNG trade is on the spot market. The balance is on the contract market.

Those competitive prices that you hear about ships being pulled one way or the other across the Atlantic Basin is on spot market and it's around ten percent of total trade. The balance is on contract pricing.

Most of the European contract LNG pricing is driven off residual fuel products, oil products. China is locking in their LNG prices on coal. Recently they secured some long-term contracts for under $4 because they are competing with coal. India successful the same way.

DR. A. DONNELLY: Well there are so many other fine speakers coming up and I feel that we need to hear from them.

PRESIDING MEMBER PFANNENSTIEL: Well let's see. Is there one more question?

DR. A. DONNELLY: Leon.

MR. BRATHWAITE: I'm Leon Brathwaite, I'm here with the California Energy Commission. Ann, I just need a small clarification, please, okay. On slide number nine you spoke about the fundamental principles of GPCM.

DR. A. DONNELLY: Yes.

MR. BRATHWAITE: Markets are competitive, prices will rise or fall to clear the market.

DR. A. DONNELLY: Yes.

MR. BRATHWAITE: But then on slide number 30 you said GPCM does not include an automatic loop feedback. So could you tell me then how does the market price rise and fall within the model if you don't have a feedback.

DR. A. DONNELLY: I'm so glad that we have Dr. Robert Brooks here because I think this is a good question for Bob Brooks to answer.

DR. BROOKS: Thank you for your question, Leon. The answer is that in any given time period GPCM is an equilibrium model. So prices will fall or rise relative to the scenarios that you have for your supply or your demand and the drivers for those scenarios.

So if you have different economic growth rates for example you're going to have different demand levels. If you have let's say two scenarios with different weather forecasts then you're going to have different demand scenarios.

And so prices, when I say they will rise or they will fall, what I really mean is they will come to an equilibrium in each time period based on the overall situation of supply and demand, given the infrastructure that you have to satisfy those demands.

When we say that there is no feedback look what I'm saying is, or what they are saying is that we don't have lagged variables in our model that will say that future demand is based on some historical pricing but rather it's based on near-term pricing. So that's the kind of feedback look that we don't have in GPCM. Does that make it clear?

PRESIDING MEMBER PFANNENSTIEL: Yes, thank you. All right, thank you. I would --

PUC COMMISSIONER BOHN: Can I -- Sorry.

PRESIDING MEMBER PFANNENSTIEL: Sorry. Another question.

PUC COMMISSIONER BOHN: Just one mechanical question.

DR. A. DONNELLY: Yes.

PUC COMMISSIONER BOHN: This is obviously an enormously complex undertaking. When one updates the model it strikes me that you have to go to a whole series of different sources which probably produce data at different times. And so you're never going to get it quite completely updated on the 100 and whatever it is.

In practice does that make any difference? I mean, are any one of these so sensitive that you the first 60 are more important than the last 43? Do you have a -- I guess my question in simplistic terms is, is there an issue as to the currency of the model at any given point?

DR. A. DONNELLY: I think there is always an issue because the minute you finalize it things begin to change in the world and so you're dealing with something that's dated. And that's why we always make it very clear what forecast we're talking about, what our base case is based upon.

And yes, that is one of the big uncertainties and the big unknowables about gas forecasting is how, what is the actual specific present state of things. Because you're really modeling something as it was input in December of 2006. And so that's why we update frequently, every six months. Bob Brooks updates every quarter and he sends us a whole new package of GPCM and everything we do from then on has all of the inputs. And so we make clear exactly what version of everything that we're using.

And certainly this is one of the big uncertainties and the big limitations of what we have done is the need to update it. Because it took us six months to do, during which time a lot of things happened. So you are absolutely bringing up a crucial point in terms of the limitations of any particular forecast. And particularly these because we did a lot over six months. Thank you.

DR. BROOKS: May I add one thing?

DR. A. DONNELLY: Bob, yes, could you add something.

DR. BROOKS: If you don't mind. What Ann said is exactly true. This is a world in which things change so frequently that if you don't update on a regular basis you are not going to get the important factors that will influence the future very strongly.

Let me just give you one example. And one which I find just based on what I've heard so far today was not mentioned very strongly, but which I think is going to have actually a huge impact on California and the rest of the country. And that is the completion in 2009 of the Rockies Express pipeline.

Of course it is in phases and part of it is already in place as you know. It started actually in 2006 with the Entrega pipeline which became Rockies Express, or phase one of that, and it is now complete over to the Cheyenne Hub. And not really a whole lot has changed since then because of course you've got constraints at the Cheyenne Hub.

But when you start moving that gas further east into the Midwest and then all the way to the Pennsylvania border you are going to have a tremendous shift in the way that gas is delivered across from the Rockies, which primarily is going west, and a lot of that gas is going to be going east.

Some of the results that Jim brought out I think are, it wasn't really specified as a cause but I think are very clearly related to the entry of Rockies Express into the infrastructure picture. In particular you noticed if you remember his basis forecast. Was it his or was that Ann's? I can't remember. It was Ann's.

The basis forecast at the California border in particular at the SoCal border, all of a sudden you have a tremendous strengthening of basis at that point. And of course that is exclusively a result of Rockies Express and the increased prices in the Rocky Mountains that are going to result from that.

So the point I'm saying is that two years ago we didn't know whether that pipeline was going to go ahead or not. Now we do. It's actually in the ground and it's going forward.

These projects are often competitive with each other. And there were a number of projects that were intended to kind of ward off Rockies Express and they didn't make it in the marketplace. But the results of your forecasts are going to depend on those kinds of competitions that occur all the time. LNG facilities, the same thing.

So if you don't update on a regular

basis certainly your near-term forecasts, the next four or five years, are going to be impacted quite a bit. And even your longer term forecasts I believe.

PRESIDING MEMBER PFANNENSTIEL: Thank you. Anything further? Thank you, Ann.

Dr. Jaske, it is now noon and the agenda has a series of other presentations and discussion before we take a break. Might I suggest that we probably should break now and then come back or is there something that you would like to get in before the break?

DR. JASKE: Well the last -- I guess it in part depends on how much time Mr. Nesbitt thinks he will spend on his version of the 5B analysis since it's a parallel piece of work on the very same topic whereas Ms. Elder's work is more general and not as specifically tied to the 5B. Perhaps if his presentation will only take a few minutes then we could get it in and it will be sort of fresh in your minds.

PRESIDING MEMBER PFANNENSTIEL: That would work for me. What is the pleasure?

ASSOCIATE MEMBER GEESMAN: I wouldn't want to slight the Altos presentation. I'd like to actually get the full-depth version of it.

PRESIDING MEMBER PFANNENSTIEL: So you think we'd be better waiting until after lunch and getting it all at once? And I notice a couple of the people on the dais have noon commitments anyway. So why don't we break until one o'clock and we will reconvene then.

(Whereupon, the lunch recess was taken.)

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AFTERNOON SESSION

PRESIDING MEMBER PFANNENSTIEL: Although everybody isn't here out of respect for the fact that we have a very full agenda for the rest of the day I would like us to reconvene and we'll start with Altos. Mr. Nesbitt.

DR. NESBITT: Thank you. I hit go show and I get the other show. Here we go.

Thank you very much. It's always fun to be the first speaker after lunch. Everybody's blood sugar is at an all-time high and their eyes are an all-time low.

I'm going to talk about two things today, I've been asked to talk about a couple of things. One is on the agenda and I submitted a preliminary version of the slide package a couple of days ago. And as usual I always reserve the right to change it so I have and I'll give you the changed version. It's only slightly changed.

And then people ask me, so how do we think about demand side scenarios for natural gas, and so I'll give you some thoughts on that as well. And more than scenarios. I don't want to use the word scenario, I want to use the word -- the way the demand side is likely to resolve in the market. Okay.

So what we'll do is two things, talk about the demand scenario 5B then we're going to talk a little bit about how gas demand even gets formed. What causes natural gas demand. Do you ever think about that? What causes it? It's worth thinking about, what causes natural gas consumption.

Because we want to talk about that in the context of the GHG and other pollution markets that are emerging and their prospective impacts throughout the WECC and throughout the country. Things like coal and things like natural gas and things like renewables.

A question was asked this morning, we're going to be talking about demand scenario 5C in the context of North America. But as you remember from the June workshop this is embedded in a full world model. Supply transport demand, LNG, existing and prospective. To every source of supply in the world, existing and prospective is represented. LNG, all the existing and prospective liquefaction, transshipment and re-gas all around the world, including but not limited to the Pacific Northwest, California and Mexico, just to set it in context.

The question addressed by Case B as it was, with the premise as it was articulated to me was, so what would happen, all out sequel, what would happen to natural gas prices and supply if California and the WECC were to institute policies that led to a serious reduction in gas burn. And we're going to talk about that in the second piece of this.

And the premise was, you could get that through high levels of renewable penetration or you could get that through high levels of energy efficiency, both for electric consumption prospectively. But it's a first order in electric generation and I'll talk about that in a minute here.

And one of the important things is the other influencing factors have to remain unchanged. You change one of those other things you're going to obfuscate the result.

So here is the picture of a base case conceptually. Everybody loves this picture now. I once had a cartoon and people said duh, what's next. It's really important. Supply and demand match, the degree of freedom to make sure they match is price. As soon as they don't match the price moves around and sucks up the difference, Merry Christmas. It's the way the world works.

What do you do to create a low demand scenario? There's really a number of details in it but at the highest level you have got to shift that demand curve leftward, that demand curve leftward, at every prospective level of price. So that's what we tried to do in crafting Case B in the World Gas Trade Model. We shifted the demand curves to the left by a magnitude that was intended to simulate the prospective impacts of renewables penetration plus conservation penetration both in power gen and for power consumption. So that's how you did it.

What has to happen in a scenario like that? Pretty simple, you go to your economics book. The supply curve has to sit still. Wherever we change supply we're changing demand. You can't change supply when you're changing demand because you obfuscate the results.

So we said, all right, we're going to change the demand curve. We're going to slip it straight left. What has to happen to the price when you do that? It better come down. Would it go up? No. What would have to happen to consumption? It has to come down. You're burning less gas at every level of price so the answer has to have less gas in it.

And I'm kind of amazed when I hear people say well, what we're doing is we're adjusting or we're adjusting something else so the supply equals demand. You don't have to do that, that happens automatically. Why would producers over-produce when demand goes down by a Tcf and a half. They wouldn't. They produce whatever the market wants and when the market stops wanting it they don't produce anymore.

And that's what these scenarios are so you can't change the supply curve. You can't change anything about supply and get a Case 5B in our model. Because it obfuscates what the incremental impact of demand is and I think that's what we want to see here.

What if demand is reduced through some policy or other initiative? So the construction of the case was very simple. In the model that we use, the World Gas Trade Model, for that portion of the model that represents the WECC we slipped the demand curve to the left at all levels of price.

And you can see in this chart, it's kind of interesting reading. We slipped it to the left by an increasing amount to simulate the policy of a fairly aggressive penetration of renewable and conservation technology in power gen and in end-use power consumption. Because keep in the back of your mind, the way you reduce power gen and fuel burning power gen, one way to do it is to reduce the consumption of power.

So we took that view in crafting this case, in working with the staff to kind of come up with what was a reasonable representation of what we meant by Case 5B. I love these monikers, 5A, 5B.

What we did since our model is running a lot longer than 2020, you're only looking at 2020, okay, we simply left a constant after that. So for those of you who see longer dates in any of the internal communication just keep in mind, oh yeah, these guys, they left the degree of percentage impact of these conservation and renewables initiatives the same. There were 31 demand curves that were impacted by the assumption to craft a case.

What are the results? I'm going t flip ahead to a slide that's not in the briefing but it's in my paper. It's this slide. Can't say anything in general about the results unless you know something about supply, unless you know something about demand. There are no generalities.

What do we know about supply in North America. God, I was so happy to hear this morning we don't have any supply problems. Supply is fine, we've got gas coming out or ears. Isn't that nice? Isn't that nice, gas everywhere. Super. I don't believe it but it's super. Gas everywhere, super. Do you believe that? We reduce LNG, no problema.

Well one thing we know if we look more carefully at the resource base, we talked about this last time. We know that in the range of $7 to $8 per MMBtu -- and we can find a rule what that exactly is. These are numbers that are very representative of what the oil industry that I work with thinks.

The long run incremental cost of production at $7 to $8, there's a whole lot of natural gas you can dig up out of the sands of

Greater Green River Basin, the Powder River Basin, San Juan Coal Beds, et cetera. But much lower than that you ain't going to get it. So what that suggests on a fundamental resource perspective is supply is somewhat elastic, that means flat, in the vicinity of $7 to $8.

And I think the comment was made this morning by the other modeler that -- or I think it was by Jim, that at prices much below that most people agree there's not a whole lot left. Most people agree there's not a whole lot of large fields left to be found in North America.

And I would like to add one comment for your consideration. I've been working a lot in Canada. I just surveyed seven projections of Canadian production by seven consultants other than me. They all drop off the end of the table at various rates. They're all down, down, down, down, down. It's not pretty what's happening in the Western Canadian Sedimentary Basin.

And even with a whole lot of tight gas that we all hear heralded in Alberta at $7 to $8 it's pretty expensive stuff. So I think the comment that Commissioner Boyd made this morning is right, we have to think pretty fundamentally about Canadian deliverability because it really drives our considerations here very hard.

And we're pretty sure -- I phoned up my colleague at the USGS, Don Gautier, who knows everything there is to know about resources, and everything he doesn't know I do, and they have done some recent assessments of the Canadian resource base and it's scary. Fifteen Tcf above approved reserves today. One-five. That's less than three years production in the Western Canadian Sedimentary Basin. We don't know if that's true but that's the number they got. So the days where the USGS is optimistic are gone about Canada.

If that's true, and I think at the last workshop we talked about one of the policy roles is to try to help people hedge against those kind of bad outcomes and help to see them coming and make better decisions. That's a serious uncertainty against which we want to hedge would be my recommendation and view.

But in any event, when we ran Case 5B, and you can look at the numbers that are in the package. If the supply curve is fairly elastic, i.e. fairly flat, the seven to eight buck range is what you'd expect about the magnitude of price drop from a conservation scenario. And you're not allowed to change the supply curve, that's cheating. What would that imply? It would imply a modest price drop.

A big volumetric impact, and we all know that's going to be the case, and that would result in significant environmental changes because you're assuming, you're pushing fewer molecules from the periodic table out into the atmosphere. That's what the environmental remediation is. Less periodic table going into the atmosphere. I don't care what it is, we just don't want to put it up there, right?

Very interesting. So if you look at those results in my package, I won't stand here and read them to you, you can see them in the package. A significant but modest price reduction in the $7 to $8 range. When you're below that you get more of a price reduction. If you see bigger price reductions than that there's some obfuscation that's gone on. People have played around with the supply curve and that's cheating.

ASSOCIATE MEMBER GEESMAN: Let me ask you, Dale, because I know you have now broadened it. In your written materials, the flatness was at $7, now it's at $7 to $8.

DR. NESBITT: Yes.

ASSOCIATE MEMBER GEESMAN: I look through the staff report, and I assume that you probably had some role in helping the staff put together the cost curves that they used, both in '05 and in 2007. I don't see any flatness.

DR. NESBITT: Well you will see it if you plot the entire curve. We didn't, we didn't plot it that way. And you have to do it in kind of an enlightened way.

One point to make, no, I didn't work on the staff report but I did provide the cost data circa, when was that, seven or eight months ago. That's the date of it. And if you look at what's gone on in the industry, the costs have escalated since then. So, you know, in my consulting work I put the $7 to $8 range out.

Those of you who have followed commodity prices all know that steel is at an all-time historical high, 15 to 20 cents a pound. The long-run historical price is five. I grew up in a copper mining town. We shut down when copper was 60 cents a pound, it's $3.25 a pound right now.

It's infinity minus just a little bit. And the same is true for all these commodities. People worry about these fundamental commodity costs and how they affect ENP.

So Commissioner Geesman, good comment. That's exactly right. People are very uncertain about these fundamental ENP costs. And it's an uncertainty that I think we want to help them think through. We don't know the answer but we want to, we want to have a pretty good range of uncertainty and have a pretty reasonable base case there.

And flatness. One of the other things about those curves that you saw in the staff report. They were aggregated across a number of difference basins and obfuscates a bit of the flatness that you really see in the Rocky Mountains. So the Rocky Mountains is really where the flatness is. Good comment.

ASSOCIATE MEMBER GEESMAN: Okay.

DR. NESBITT: Okay. So you've seen these diagrams. One of the other things, everybody please raise your right hand and repeat after me, supply equals demand in the market. So if you want to look at how demand varies with price, you're also looking at how price varies -- supply varies with price because supply equals demand.

And so the first two slides in my pack are really the same thing. That's why. Supply and demand are the same. There are minor differences because some of the supplies are viewed to be external in the Gulf of Mexico, i.e. LNG, rather than internal in the supply case. That's not true in the demand case. But if you look at my two supply scenarios in that chart. Excuse me, I have two scenarios for demand and supply, they're very much the similar.

If we look at the last one, the Henry Hub price track, we've only plotted for this briefing Henry Hub but we have Topock and Malin and every other hub in there.

You'll notice just as the conceptual charts show that the purple, which is case 5B, does in fact lead to a small price depression everywhere and certainly it's manifested in henry Hub. Even though Case 5B, the mandate we had was to implement these conservation renewables changes only in the WECC and to leave the rest of the US and Canada outside the WECC constant at the Altos levels. And you recall from the last workshop the discussions regarding that I think.

Okay. So there's an Altos report and Commissioner Geesman has cited -- I think it's available on the front. I haven't gotten a Nobel Prize for it yet, I don't think we're in line.

Questions about that? Because I want to chat a little bit about -- I was asked to chat about formation of demand.

What the staff asked me to do is to think a little bit conceptually about the role of renewables and the role of environmental law in forming gas demand. And so with about 15 or 20 minutes I'll do that.

And please view this as discussion-oriented and conceptually-oriented so that we can think fundamentally both from a modeling and from a real world perspective how in the world gas demand gets formed, particularly in the power gen sector. And that we as policy makers or policy advisors, how do various policies, renewables policies, carbon counting policies and so forth, impact that. Because the impacts are not small but very large.

And I think we recognize that. That's

why we set up scenarios, you know, one through five, alphabet through D. That's why we did that, we know it's important.

The environment is a 500 pound gorilla, we know that. What does that mean? That's not a bad statement, it is not an editorial statement. But it means it has a massive affect and the affect is just about to grow a whole lot on the power gen sector.

Why is that? SO2. Does everybody know what is going to happen to SO2 in 2010? It's going to be cut in half. Every entitlement is only going to be worth half a ton. So we're going to go from 9200 tons to 4500 tons, give or take. Boom, just like that, we' know it's coming.

Does everybody know what's going to happen to NOx? NOx is going to go from the 29 SIP call states, summer season only, to I think it's 39, I'd have to go back and look, states, where some states are summer only, some states are year round. Like Texas has to be year-round now. And some states are year-round and summer. So the NOx constraints are really going to start binding in the year 2010.

Mercury. Mercury is coming on federally

in 2010. Many states had mercury on spot requirements already. Particularly Illinois and Pittsburgh -- Pennsylvania. Pittsburgh. That's important because it really hammers coal in those states. And if we hammer coal in those states what happens to gas burn? It ain't that hard a question, is it?

ASSOCIATE MEMBER GEESMAN: Well let me ask you. Is it your belief that these environmental influences will affect economics of generation and that plants will continue to be dispatched economically?

DR. NESBITT: No.

ASSOCIATE MEMBER GEESMAN: Or that on a qualitative basis it will affect the dispatch order itself.

DR. NESBITT: It is already affecting the dispatch and the retrofit order. And if Senator Boxer has her way it's very interesting with carbon. She doesn't want to mail presents out to everybody in the form of carbon entitlements. What she wants to do is put them in a central bank and everybody will have to bid on a zero base basis. Commissioner Geesman, great question. If that happens they will be in the dispatch stack.

Under FASBI today they must be in the dispatch stack, even though there are regulators that don't want that to happen. They want to hand the largesse that's mailed out to generators in their service territory from the federal government over to ratepayers.

So right now with regulated utilities there's some question. But with merchants, and if there is any bidding out of a central bank for these things you can bet your bottom dollar they are already in dispatch and it's only growing. Absolutely. That's the intent.

If you go to the EPA office of clean air policy and you say hey, those guys are not dispatching plants with your SOx and NOx prices they break out in a rash. They hate it. That's not the intent of those regulations. The intent of those regulations is to internalize the externality and to power -- and to hand those higher costs over to generators and to ratepayers. That's the intent.

Particulates are coming. We know particulates cause cancer, we know. These policies, it's very interesting. These are differentially deleterious to what? I give up. Coal. They all hammer coal differentially, deleteriously, to every other generation source. Keep that one in the back of your mind.

An lot of people have said, and it's a good way to think about it even though I don't totally agree with the sense of it, existing and new environmental regs are a subsidy of everything but coal. To hammer coal then they're a subsidy of everything else, right?

Just like God wrote in the Bible, if you hammer one consultant you've helped everybody else. If you hammer one Energy Commission you help everybody else. Darwinian natural selection. It's very important to think of it that way. And that's the intent. Go to the Office of Clean Air Markets and ask if that's the intent. Yeah, that's the intent. That's the intent.

One of the things to keep in the back of your mind is that high renewable scenarios are high gas burn cases, not low gas burn cases. Because what are these environmental laws and regulations intended to do? Show of hands. Do you think they're intended to reduce gas demand? No. You think they're intended to knock coal out of the stack? Just go over to the rotunda and ask. That's what they're intended to do is cut coal. Cut coal is the only way you can generate a marginal entitlement.

So high renewable scenarios, which many people are in favor of, are high gas demand, not low gas demand scenarios. The way you get low gas demand is lots of coals. Economic dispatch, that will do it for you. Very interesting. So what we're looking at is high coal scenarios here. We're not looking at high renewable scenarios. That's what I think.

So the gas burning power gen, we're going to go a little further with this, is extremely sensitive to all these caps. You can't guess what's going to happen with one of these caps because there are massive co-benefits.

If you put a scrubber on your plant the incremental efficacy of the other methodology, safe carbon or better. These things interact. These are hard to think about without a model. Let's look at some numbers. Anybody want to run through that? No they don't.

But if you take a pulverized coal unit running naked, no environmental hit at all, there's your fuel price at $2.20 coal. There's your variable O&M and your fixed O&M. You're going to dispatch that unit in the high 30s.

When you load at today's levels, not tomorrow's levels, SOx, NOx, mercury at 35 million a ton, which is below what most people think is going to come in, and CO2 at $15 a ton, that plant dispatches at close to $100 a megawatt hour, nowhere near the 35 economically.

Go over to natural gas. What happens with natural gas? Big misconception here that somehow natural gas is carbon unfriendly. It's not. Natural gas produces carbon at about 40 percent of the rate of a coal plant. I don't understand how we think that natural gas is an environmental hit, it's not. It's not.

And we look at loading a natural gas plant. Yeah, we make some NOx in those plants, and this is one without an SCR, selective catalytic reduction. And they make a little bit of carbon. They only make carbon at about 40 percent of the rate of a coal plant.

So if we look just at these stack charts what are these regulations going to do? They're going to drive these emissions prices to the point at which coal doesn't dispatch anymore.

As that happens there is room for what? A renewables/gas mix. There is no such thing as an all-renewables portfolio. Why? What fraction of the time does the sun shine? Now when I watch the world series the sun ain't shining. I want to watch it at night. When the wind blows what fraction of the time does the wind blow? Forty percent is a big number.

So we need backup. If we're going to backup we don't want to generate with our backup but we need backup. Public safety and economic growth and those kinds of things are at stake.

What is the logical backup for renewables? Show of hands. Coal? Do you want to back up renewables with a coal plant? I don't. You want to back them up with other renewables? You'll end up like Denmark would look without French nuclear to underwrite it. That wouldn't be pretty. No, you want natural gas. You want black start natural gas that only runs when you need it because you want the renewables running because their incremental short-term cost is so low. But you need the backup for natural gas.

So a high renewables scenario is a high

gas burn or a low gas burn scenario? You guys tell me. It's a high gas burn scenario, it's not a low gas burn scenario. I think we're on the wrong page here. You have a high coal scenario here, you've got five of them in my view. Right? They're a lot of fun.

Now one of the other things, this is heresy but so what. EA scenarios, that means emissions allowance scenarios where you guess SOx, NOx, merc and CO2 prices, are an utter waste of time because you always get them wrong. Why? They're endogenous to the closed system.

When you cap carbon the carbon price must rise to the point where all fuel prices considered, you knock the last coal plant out of the stack and you bring the last gas plant in and you generate the marginal entitlement. Emissions allowance prices are endogenous to the system, they're not exogenous to the system.

This is really important thinking. You can't run and have any $7, a $10, a $15, a $20, a $30 CO2 price, because they are all wrong. The one that's right is the one that makes sure you hit the cap. Or if Lieberman, Warner, McCain come in. Those are caps, those are not taxes. There's a safety valve in there but those are caps.

And you never get the right scenario unless you have it endogenized. And you'll find when you endogenize, say a Lieberman/Warner carbon cap. You know how high the carbon price has to get to hit the cap? Nothing the matter with this but you know how high it has to be in a closed system? Take a guess. $50, $50 a ton. Now there's nothing the matter with that but that's what it takes if you build yourself a closed power emissions model to hit the cap. $50 a ton is a lot but that's what it is.

Okay, so let's talk a little bit, how does the world work. It doesn't work with independent dispatch with exogenously given emission entitlement prices. No, no, no. Federal law says there's 18,500 power plants. They're all eating emissions allowances if they want to generate. Those power plants are a demand curve for supply.

And the EPA Office of Clean Air Markets sets the supply curve. They have been chartered by Congressional law to set it. There's a big process for setting it. There's a lot of blood in the snow before it gets set but it gets set. And it gets set to hit health and property damage kinds of considerations. These are serious considerations and there's no political movement that I know of against it. People like that. They like the fact that acid rain isn't damaging things anymore. So these caps are in and they're coming down.

And there they are. It's a picture of the sulfate cap. It's a picture of the NOx cap. And I'll make these slides available to those of you want them so you can look at those.

So power price is a function of emissions price and emissions price is a function of power price. Just like God wrote in the economics book and the Bible, they're the same. You cannot guess emissions prices independently of fuel prices and you cannot guess fuel prices independently of emissions prices. All this correlation stuff is preposterous, you can't do that. You can't do that.

A famous story that I'll tell you. It was during the Microsoft anti-trust hearings. Schmalensee was on an airplane. Schmalensee the great economist from, I think it's Harvard or MIT, I forgot.

SPEAKER IN THE AUDIENCE: MIT.

DR. NESBITT: MIT. Hey, I knew there would be a guy with a brass rat who'd tell me that. But he went to that thing and they were talking about correlations and so forth. And he said, you know, I was flying in here and one of the things that I noticed. Every darn time I fasten my seat belt the air gets rough. I fasten my seat belt, a little light goes on and the air gets rough. So I'm not fastening my seat belt anymore, I don't want the rough air. Causality and correlation are so far apart it's preposterous.

I want to say something about oil too. So this is the model that we use to generate the demand side of Case 5B in your base case. A fully linked world and North America model. We chatted about it last time. I just wanted you to know when you do that, that I think thinking of a low gas demand case as a conservation case just isn't right. Conservation and environmental remediation and renewables are a bigger issue than gas demand.

Oil. I do want to say something about oil with the amount of time I have. Anybody know -- You might get out your pen. This is a really useful thing to know. How much residual oil is produced in the United States of America? Nobody knows. We battle about oil and gas. I didn't know, I looked it up last week. What do you think the answer is?

How much residual oil could substitute for gas? Because all the other transportation fuels ain't going to substitute for gas, they have higher value use somewhere else. How much residual oil do we produce in North America? Any guesses? .9 million barrels a day. .9 million barrels. There ain't any resid produced anymore.

Why? Because the cracking margin between crude oil and product is infinity minus a little bit. It's $30 a barrel, it's $40 a barrel. Why do you think Chevron and Exxon/Mobil and Shell and all those guys want to retrofit their refineries? Because they're making so much money you can't stick it in pillowcases that they can afford to buy, that's why. They don't make residual oil anymore.

So now here we come. And by the way, the people at the Federal Reserve Bank, I know Steve Brown, I know Mine Y□cel, I know the work really well. That work suffers from cointegration problems. There's newer work that's out there that doesn't co-integrate. And that newer work, as I understand it, says there is absolutely, fundamentally no connection between crude oil price and natural gas. And the natural gas sets the price of resid, resid does not set the price of natural gas.

Resid is a by-product that has to be hauled off the refinery lot when you can't refine anymore. And you will sell it at whatever you can get for it and it's well below the price of gasoline. Gasoline is about -- What, oil is about 11 bucks a million, gasoline is about $15 MBtu now. You're not selling that residual oil for that, you're selling it at the paltry $6.50 that you get in the gas markets.

So any idea that oil and gas prices were connected. Yeah, they were connected back in the '70s and '80s because we were making four to eight million barrels a day out of a lousy non-retrofit refinery system because we didn't get the kinds of values for transportation fuels we get now.

So back in the '70s, as Susan Holt of EIA said the other day, fuel substitution is the problem with the 1970s. It's not the problem of the year 2007.

The other thing to keep in the back of your mind, how many power plants do you know have an oil tank on site? Zero. Nobody from Calpine to Duke to anybody else has put an oil tank on their site in 12 years. They just don't do it. There is no substitutability left in the electric sector save the Northeast and save Florida. There's none in the WECC. And there is no propensity to bring it back.

It's very hard to believe that there is any connection between oil and natural gas prices left in the system.

The last thought I'll leave you with so you have the idea on the demand scenarios that I think we should be considering here are your higher demand scenarios coupled with lower coal consumption. That's our policy goal I thought. Is that our policy goal? Getting rid of the dirt, getting rid of the gasses we don't like. We don't like anything from the periodic table going into the atmosphere. Anybody like anything going into the atmosphere from the periodic table other than Chanel Number 5?

SPEAKER IN AUDIENCE: Oxygen.

DR. NESBITT: Hey, there's one good -- You know, that's a good answer. These modelers are good. Okay. So that's a very important consideration. How does conservation affect natural gas? It's very interesting. We've talked about it on the electric side.

Conservation, most people think, most modelers like me think, that conservation on the power side will not offset the shift away from coal under these environmental laws.

How about conservation on the natural gas side in the traditional, residential, commercial and industrial sectors. The last thought I'll leave you with. Well if you go look at the market out there there's hardly any industrial sector left in North America. God, I hate it when that happens.

A good-sized fraction of the industrial sector is what? Behind the fence generation hooked up to the grid. It ain't industrial demand at all. So you're not going to have much, you don't have much of an industrial sectors to substitute the oil in anyway, or coal in anyway. The substitution is in utility, plus merchant, plus behind the fence generation. That's where the sub is.

And we're pretty darn sure we know because we see the power once they're reported to EIA. Every power plant bigger than one megawatt is reported every year. And their whole configuration and substitutability is reported. We don't have to guess about this, we know there's no substitutability left on power gen so therefore there is very little substitutability left on the gas side.

And there ain't no resid anyway. So that's a very important consideration. I think one of the comments that was made this morning, we really do have to worry about these domestic sources of supply. Absolutely, that's what we've got to worry about. And we have to worry about what these environmental policies that I think everybody wants, or at least most people say they want, to ameliorate release of whatever gasses there are into the atmosphere, are going to stimulate gas demand structurally.

Okay, we can go through a whole bunch of scenarios on the environment. I don't think I'll do that. Have I exhausted my time? Thank you.

PRESIDING MEMBER PFANNENSTIEL: Thank

you, Dr. Nesbitt. Are there questions?

PUC COMMISSIONER BOHN: I have some.

PRESIDING MEMBER PFANNENSTIEL: Yes, Commissioner Bohn.

PUC COMMISSIONER BONN: Two. There are some folks at CalTech that will say all of this is a very interesting discussion but none of it matters because you can't scale enough of it fast enough to be able to deal with any of the projections that have been made, whether it's west coast or national.

You simply can't get there. You cannot produce out of all the renewables you could possibly do, all the nuclear you could possibly do over the next scenario that we have outlined in this country. My question is, would you comment on that. And secondly, you make no mention of nuclear and I'm curious where that fits in.

DR. NESBITT: That's very interesting and it's a darn good point. Notice I had sent up sensitivities that I ran right there in my environmental model. And if you want to see them I'll show them to you privately later and we'll sit down and look at number three.

While we're sitting here today the stock market is going down another 200 points. Why? Our interest rates are too low, that's why. We can't attract international debt. So when those interest rates go up I'm going to agree with you in spades.

When those interest rates go up any capital equipment, be it renewable, be it coal, be it nuclear, et cetera, are going to get hammered because discount rates hammer capital formation. Interest rates, market rates of interest hammer capital formation.

Now take that thought. Where is capital formation biggest? It used to be nuclear. Nuclear used to be more expensive than coal, it's not now. Most people think you can build a nuclear plant for -- you can write this down, it's the latest number I've seen, $2400 per installed kilowatt. Overnight construction, cap rate interest on top of it.

The last number I saw from DOE for integrated gas combined cycle with carbon sequestration based on coal, $3,800 a kilowatt, 50 percent higher than nuke.

The issue with coal and nuke now, and a senior VP from Puget presented it a couple of weeks ago when I saw him. He said, if we build one pulverized coal plant today it will cost us about $3 billion for 1,000 megawatts. That's 20 percent of our load and it would take our entire market cap. There were $3 billion. So he looked at me and said, hey, Dale, why don't you take that to the Board. I said, I don't think I will.

So if we look at the chunks that are required to build nuclear vis-…-vis the size of your typical utility you're talking oil company investments, you're not talking utility investments.

So I think the big issue with regard to coal and nuclear, but it's not there with regard to conventional combined cycle and simple cycle combustion turbine, is the size of balance sheet commitment that you have to ask a utility to take to build just one unit. And then they have to go to their regulators and they have to slide $3 billion risk-free through in rates. Dale Nesbitt is not going to take that to his board, it's too risky. A really good question. So nuclear and coal are really hurting.

If those discount rates go up, as they have been doing, that's why the market has been crashing. When you say we have a liquidity crisis what's that mean? The interest rates are too low. Nobody wants to lend you money, you've got to raise up. You've got to get somebody to lend you money. That's a really good question.

I think coal and nuclear are in a serious world of hurt because of the high cost of capital that we have out there. And the high capital cost because of these commodities. It's one of the main reasons coal plants are being rescheduled. A lot of people are getting nuclear permits but you haven't seen anybody stick a shovel in the ground and twist rebar and pour concrete over it. Very, very tough right now.

ASSOCIATE MEMBER GEESMAN: So what was your reaction to our staff's reduction of their assumed level of LNG imports to North America?

DR. NESBITT: My own view is it is too low. My own view. You asked the question I think Commissioner Geesman, it was a good question. So if you pull the cork out of the bottle Homo Economicus, the economic man, there were no constraints at all against any part of the LNG supply chain or any natural gas supply chain, how much LNG would be profitably absorbed onto the

North American continent without an overbuild?

And the answer is about 50 percent of gas supply 20 years from now. We ain't got any natural gas, come on guys. Natural gas is in severe high cost supply relative to LNG. Everybody in the oil industry knows this and everybody in the governments knows this. And that if we have to rely on that $7 or $8 gas rather than the $4.50 LNG that we bring in we have a $2 to $3 gas price differential we're imposing on ourselves.

And I think when Mr. Fore presented the staff forecast, that what was in there, we were drilling these half a Bcf and less holes. Basketball-size formations on eight acre spacing. The land acquisition cost of that alone and the land displacement cost, we haven't seen in this country ever. You haven't seen eight acre drilling with a gathering system covering Wyoming. It's very interesting to think about what that forecast means.

I personally think, this is Dale Nesbitt speaking, you're going to see a lot more LNG than any of us thinks. A lot more.

PRESIDING MEMBER PFANNENSTIEL: Other

questions? Are there questions from the audience?

Thank you Dr. Nesbitt.

DR. NESBITT: Thank you.

PRESIDING MEMBER PFANNENSTIEL: I believe we'll move to Catie Elder.

MS. ELDER: Hi, I'm Catie Elder with RW Beck and I have to turn on this thing and I guess it's not working right because it's on but I don't hear anything.

PRESIDING MEMBER PFANNENSTIEL: Yes, it's working, Catie.

MS. ELDER: It is working?

PRESIDING MEMBER PFANNENSTIEL: Yes.

MS. ELDER: Okay. If you've seen me at one of these workshops before, I can't stand standing behind that thing because I can't see anybody and I know nobody can see me. My brother is about six-foot-three and I can always hear him saying, Catie stand up, and you can tell I already am. So we'll try to fix that by using the hand mic and I'll wander around a little bit.

Dale is a tough act to follow so take a deep breath with me and we'll try to walk through batting cleanup here. I have to figure out whether to hit the page down arrow -- the page down button or the down arrow key.

All right, let me just talk really quickly about RW Beck's role was here. We worked with the staff, kind of alongside the staff. Kind of being a second set of eyes questioning things, pointing people in the right direction. Not so much saying whether we thought the analysis was right, wrong or whatever but just trying to clarify things. Make sure that -- Help them explain the results that they were seeing. Kind of test, reality check test it a little bit.

We also in that context provided some alternate supply and demand scenarios that I'm going to show to you. If you were here at the workshop on June 7, they have not changed a whole lot. Particularly the demand scenario alternative has not changed by very much. The supply has changed by a bit and the change to it is actually important and it will highlight something that Dale actually said. So I'll take a little bit more time with it than I will with the demand.

As Ann mentioned earlier we participated somewhat in reviewing the low gas demand scenarios that Global ran. We didn't, that is to say, that we participated in the discussions. We looked at the results. We probably didn't get as much time with that as we would have liked and we would have liked to have been more helpful. But we at least saw them and sort of know the gist of where Global was able to get with those.

The RW Beck team consisted of myself, my colleague Dr. Youssef Hegazy who is not here today. At the last workshop we had Youssef connected via phone and he kind of came across as the voice of God when I needed somebody to answer a question for me. But we don't have Youssef today so you're stuck with me.

Now one of the questions that we were asked early on was why are forecasts always wrong. And lots of us who do this all day long, and Dale, the gas unit staff, we all know that they end up being wrong often because the assumed conditions, the assumptions that went into the forecast don't hold true. And we know when we make those assumptions that a bunch of them aren't going to hold true but we have to make some sort of assumption.

Very often another thing that is important to keep in mind is that those assumptions that we make depend on outcomes that can't be predicted. The weather is a great one. A couple of years ago in August when natural gas prices were at about seven bucks per MMBtu, roughly today as a matter of fact, two years ago almost today I put out a market memorandum to a number of RW Beck clients and said, watch what happens the fourth week, bid week of August. If there is a hurricane in the Gulf during bid of August gas prices are going to 14 bucks.

Well the bad news is that there was a hurricane in the Gulf that week, Katrina to be exact, and natural gas prices for October and September did go to $14 per MMBtu.

My prediction, however, was based on a huge if statement. So the if statement was, if there is a hurricane in the Gulf. Embedded in our forecast lots of times, very, very often there are lots of if statements. And when people look at the results they all forget the if statements but the if statements are really important.

Now our view, and this is where I really wish that Youssef were here because he can articulate this much better than I can. He has built a stochastic market price model for electricity prices for RW Beck and is aching to do one for natural gas. But our view is that the best approach is a stochastic model.

It's not quite like the stochastic model Ann was describing that Global was using. Our view is a little bit different. We would actually put the stochastics around each of the input variables so that you allow whether to vary. You allow outages on the electric side to vary. You allow, on the gas side it might be production per well. It might be the number of wells that you drill. It might be demand. We would let all of those things vary and assess the outcome and create a range of natural gas prices associated with that.

Now the staff has traditionally in preparing the IEPR prepared a deterministic natural gas price forecast. It sounds like it may be possible, in conversations that I have had with Altos it sounds like it may be possible to do that with Altos' model but staff was not in a position to really evaluate that or do that previously.

The alternative beyond what we've been able to put together here, which is, you know, admittedly a band-aid approach.

The alternatives that RW Beck has

prepared for both demand and supply will give you a sense of how things could be different but we never get to the point of taking those alternatives and actually putting them into the model and saying, what does that do to price. So we're giving you some alternate views or ways to think about demand or to think about supply but the fruition of those has not been evaluated.

The way that one could do that would be to take the model the way that staff has been using it and do a lot, a lot, a lot, a lot of iterations to create bounds around a reference case. That would almost consist of a stand-alone scenarios project for natural gas. Very time consuming, very resource intensive.

And if you make a change to the reference case, as we have done between June and now, you would then have to go back and rerun all of your iterations. So that's why we suggested that a stochastic approach to begin with probably makes more sense.

Now we selected -- I'm not exactly sure if we selected or if staff selected now that I think about this. But bottom line the realization was that demand and supply were two incredibly important values for forecasting natural gas prices. And as much as we talk about a demand assumption or a supply assumption they are both very, very uncertain. It is not like we know with any certainty at all what demand is going to be.

That's part of what you're seeing in the scenarios project, evaluating lower natural gas demand. We're going to talk about some other things that could affect natural gas demand.

The same thing is true in supply. I'm going to show you some things around supply. If you were confused about supply before you may be even more confused by the time I'm done. But we'll see if we can fix that.

A key factor that affects demand, and Dale was trying to get at this. A key, absolute key factor affecting demand for natural gas is how much natural gas gets borne to generate electricity.

The scenarios project demonstrates lower natural gas demand. I can't talk now. Natural gas demand declines as you implement a higher renewable portfolio standard or you implement a higher energy efficiency standard.

Now that happens in the WECC and in

California because there is not a lot of coal in the mix to begin with. I'll talk more about that later, the importance of that later.

But we also know that how much gas you get to generate electricity is going to be affected by the emissions regulations that are put in place besides just the RPS and the energy efficiency, but what exactly do we do in terms of restricting carbon.

That's going to drive allowance values, that's going to drive the changing -- going to have an impact on the changing capital costs between coal versus gas. You've got some exogenous factors Dale mentioned like steel prices affecting capital costs for coal.

What happens with IGCC, what prices become economic add, does sequestration actually get proven? What happens to cost of renewables? How much is energy efficiency cost? All of those things are going to drive what goes into the natural gas demand forecast because it drives how much gas gets burned to generate electricity.

Now staff's forecast is similar, staff's demand forecast is very similar to that that the Energy Information Administration put out in its annual energy outlook in the early years, up to about 2011. There's a graph in the report that demonstrates this. I did not put the graph in this presentation package so you'll have to flip through the report to find it.

And then after 2011 it diverges. It becomes higher than EIA's by about half a trillion cubic feet to about .75 trillion cubic feet per year.

Beck's analysis, and that's the analysis done by my colleague, Dr. Hegazy, suggested that a range of plausible demand around the staff reference case could be 1.5 to 2 trillion cubic feet either side of staff's reference case. So a bunch of factors that we think that could push natural gas demand lower. They could be as large as a Tcf and a half, maybe two Tcf. Opposite side on the high side we could go that much higher.

Now I sort of get driven nuts by people who say that we can't produce enough natural gas. And maybe it's just a matter of semantics but I think the reality is that we can produce as much gas as we are willing to pay for.

Producers have decided that it is more economic to produce natural gas elsewhere and bring that natural gas to the US as LNG. So it's not really a matter of whether we can or we can't produce the gas, it's a matter of what price we're willing to pay for.

We see that in a couple of different ways. The reserve base, it's easy to demonstrate the reserve base has grown consistently. We've replaced more gas than we've burned, we've done it for years. But a lot of those reserves are unconventional, which means that they produce at different rates than conventional reserves. They actually produce at smaller rates than conventional reserves.

They are actually riskier to drill. So when you look at a risk-based assessment of where a producer is going to spend their money they are very often looking for conventional reserves elsewhere, offshore, someplace not in the US. Like Australia, Nigeria, Qatar, et cetera.

The fact that we are seeing so much LNG become available in the world trade market is really a function of the fact that producers have decided that that's where they want to invest their E&P dollars.

So the bottom line is that from this

view really LNG becomes a price-taker here at the US. It will take whatever our domestic, market claim domestic natural gas prices and we'll have a fabulous net back because it costs so much less for them to produce than it costs us to produce. And that will then reduce the need -- More LNG coming in reduces our need to produce natural gas. And that effectively reduces prices or caps prices. And we're going to see that between the staff's preliminary reference case and its revised reference case.

To look at supply and the potential impact on supply or the potential uncertainty around supply we've built a very simple model. And calling it a model might be giving it more sophistication than it deserves. What we've essentially done is figured out how we could describe domestic supply.

And realize that we could describe domestic supply by talking about depletion. How much gas we started with. We deplete that by X amount every year. We then add, figure out how many wells get drilled. Production per well of some amount times the number of wells drilled less what you had to begin with creates domestic production.

Now if we add demand to that equation and we compare demand versus domestic production we get a difference, depending on your supply scenario you may get a difference between the two. And that will tell you essentially how much LNG needs to come in at that domestic production level.

We are not talking about what happens with prices in this very simple heuristic. Prices will rise and fall depending on what happens with that quantity of domestic production and how much LNG comes in to push this back down the supply curve. So we're not trying to make a statement about prices with this very quick view of how supply could be constructed.

Now sort of the interesting thing is that we can change either depletion, the number of wells drilled or production per well and that's going to change or show us what the impact is on production. And so we can sit back and we can play and say, well, you know, if you want to produce 20 trillion cubic feet and you think production per well is going to do this doesn't imply how many wells you're going to go drill.

And that's what I'm about to show you.

Now the detailed tables in which this gets done are actually buried in -- are we in Chapter 6 now or did the chapters get renumbered? Alternatives, are we 6 or 7? I can't remember. We were 6, we may have changed to 7. Lorraine thinks we're still Chapter 6. But if you look in Chapter 6 you'll see three tables, a reference case, a high supply case and a low supply case. And you can see how the variables that I just talked about get stacked up to tell you how much domestic natural gas to get produced using these assumptions.

This table compares staff's preliminary case. I'd forgotten that I put the pointer thing in my pocket. So we've got -- These are the numbers from staff's original preliminary case. These are the updated numbers from the new reference case.

This is a high supply case, this is a low supply case. We have the depletion loss very year set at the same thing in all the scenarios, so -2 percent. Supply shrinks by two percent every year due to depletion. And that is just the amount of gas that we've produced that we have now lost and we can't produce it again.

Now in the preliminary case out in 2017 when I used that depletion loss assumption I had production per well declining at four percent and I had Canadian imports declining at 2.8 percent, which was based on a Natural Resources Canada forecast.

I ended up, we ended up saying that there would be about 7.1 trillion cubic feet per year of LNG coming into the US. That has not changed. That would then imply that to get there our domestic production number, we had to drill 45,212 wells.

But we reduced the amount of LNG coming in to the US so now we're talking about 4.5 trillion cubic feet. We've lost about roughly three trillion cubic feet of Tcf by going from that 24 Bcf per day down to 14 Bcf per day the staff just talked about.

And my numbers here are US, not North America. So if you're trying to add them up you may not be able to get them to add up quite that way. What you see was with all the same assumptions I actually changed the Canadian import by just a little bit to update it for staff's most recent number used in the forecast.

But the big change here, since we have that much less LNG coming in, the big change is we're now forecasting drilling almost 60,000 wells per year by 2027. That's a huge increase, almost 15,000 more wells have to get drilled in the year 2017 than we had said in the preliminary case. And I thought when we did the preliminary case that 45,000 wells drilled per year was rather heroic given that we drilled about 30,000 in the past year.

One of the implications of constraining the amount of LNG that we have coming in to North America is that we have to go drill more gas. And we're not talking about drilling a little bit more gas, we're talking about drilling a lot more gas. That's a lot of wells to have to go out and drill.

ASSOCIATE MEMBER GEESMAN: But in your assumed environment wouldn't the industry find better returns drilling wells elsewhere than the US or North America?

MS. ELDER: I believe that that's probably correct, that there are better returns drilling gas elsewhere, not here in the US. And so the question that I think you're hinting at is, Catie, how on earth would we ever expect to drill 60,000 wells if the returns are better elsewhere.

ASSOCIATE MEMBER GEESMAN: I'm still hung up on 45,000.

MS. ELDER: I hear you, I hear you. I think 45,000 was a lot too. But the implication is that 45,000 -- and this production per well number is declining at four percent here. The actual decline, there is a table in our section of the report that shows that the actual decline in production per well over about the last eight years is seven percent. I was generous when I used four percent.

ASSOCIATE MEMBER GEESMAN: So that doesn't make me any more enthusiastic about investing in a new well in North America I don't think.

MS. ELDER: That's exactly right, that's exactly right. Now what this makes me wonder is whether, you know, we've understated the price impacts. That's where it leads me. Because where this sort of -- looking at the supplies it sort of leads me as to wonder whether or not we've understated the price impacts.

I was going to try to broadly summarize

what I see when I look at staff's reference case results. Kind of this batting clean-up that I mentioned earlier.

We've seen and I have already mentioned here, and I think Jim Fore mentioned or emphasized the key outcome of the preliminary case was that we saw a lot of LNG come into the US. We had 24 Bcf a day coming in to North America. It was roughly, if you looked at the reference case supply heuristic that I had in the preliminary assessment I think that came out to be about seven trillion cubic feet per year, roughly.

It ended up being by 2017 about 20 percent of the supply mix. Now the interesting thing is that the comments that staff got back, even from LNG developers, was that that was too much LNG coming in to the US.

It turned out that the amount that staff had coming in was roughly half of what Jim Jensen suggested would be available worldwide. So in essence we were saying it was economic, the world gas trade model basically said it's economic, or it will be economic, for half the world's LNG to come to the US.

Even LNG developers suggested that was

too much. So the bottom line is that staff went into the model and constrained the amount of LNG that could come in.

Now I have my druthers and I'm going to say this with all kindness to staff because they know I think this, and I don't mean it to sound like a dig at all. It would have been my preference to go into the world gas trade model and understand the economics underlying it that caused it to send 24 billion cubic feet a year to the US, to North America, in terms of LNG.

And instead what we did is say, we don't really have time to do that, it would take a lot of effort. We don't know that model as well as we know the NARG model. So what we're going to do is we're going to constrain the amount of LNG that comes into the US.

So the model though if left to its own devices, and Jim Fore said this this morning, the model if left to its own devices would still send 24 billion cubic feet per day of LNG into the US and the natural gas prices would be roughly $1 lower per MMBtu.

PUC COMMISSIONER BONN: Excuse me, are we talking about the same world gas trade model that was referred to in I guess Dr. Brooks' model? I mean, are we talking about the same thing? Because the model of the global marketplace done in an analogous way, that is to say taking all the known sources of production and all the stuff that they did and do it for the United States. I assume that that model does the same thing for the world. Are we talking about the same models or are they different models?

MS. ELDER: Two different concepts here. The Altos model that staff uses has a world gas trade component to it. And there was a graphic that Dale had up on a screen maybe half-an-hour ago that showed for the blocks of different supply sources and arrows showing how those got traded all over the world. That underlies the staff's work here.

What Ann Donnelly. explained this morning about Global's model was that it did not have a world trade model behind it. Ann is nodding. I'm looking at Ann to make sure I'm characterizing this correctly.

DR. A. DONNELLY: The Brooks model assumes that whatever LNG is --

PRESIDING MEMBER PFANNENSTIEL: Ann, you

need to come to a mic.

DR. A. DONNELLY: Yes. The Brooks model assumes that whatever LNG is needed to fill the demand, comes in.

PUC COMMISSIONER BOHN: I'm sorry, then I misunderstood one of the points that was made before. I thought when he was up there he said something about that the modeling, the relationship modeling that you guys built relied on some kind of a world market model in order to deal with that. Am I just mistaken?

DR. A. DONNELLY: Well there is one component of the price the way it's set for LNG and GPCM, and that is that it relies on prices competitive in Europe, Asia, et cetera. So there is a price portion of the world situation for LNG that is incorporated in GPCM but it doesn't constrain the volume.

And I'm sorry, I may not be able to dig deeply enough into it to really answer your question. But there is a world component that -- to just resummarize that, the Brooks model does not use a world LNG model to decide how much LNG is coming in to the US and into their model. But it does use world price relationships to tell us within GPCM what the price of LNG will be when it does come in.

PUC COMMISSIONER BONN: And the price being a resultant of a series of purchases and sales globally generated should give you some proxy, should it not, as to how the market, the global market works or am I putting to much into it?

DR. A. DONNELLY: No, that's correct, that's correct. It impacts price but it does not impact volume directly as it comes into the GPCM model.

DR. NESBITT: One quick clarification. You can sit down and you can guess what prices are in Zeebrugge. Go ahead, what do you think the price is in Zeebrugge? What do you think the price is in Tokyo? You don't know, do you? You need a model to tell you that. At least I'm not smart enough to think about it. Do you know what the price in Zeebrugge, Belgium is right now? No. It's changed. Last year it was $16, today it's $3.50.

So what we found and what you see in the world gas trade model that your staff is using is that those relationships are laid out explicitly with supply. You've got to know how much gas is next to the water I should think. LNG, you've got to know what it costs you to build a big old refrigerator over in Qatar on the north field and turn it into liquid.

Then boats, they're only 600 million bucks a copy. You only need nine of them to get gas here from Qatar, you better know what those cost. You need to dispatch these boats and dispatch those supplies around the world or I would argue you won't have a clue what LNG costs in terms of the long-run marginal cost basis here. And if you don't know that, how are you going to figure out how much LNG gets imported.

PUC COMMISSIONER BOHN: Don't you have to know the sort of projections for global demand as well?

DR. NESBITT: Absolutely. Supply, transport, demand, piped worldwide, absolutely.

PUC COMMISSIONER BOHN: Is it the case that the model that the staff is using does that to your satisfaction?

DR. NESBITT: Not only to my satisfaction, it does it well. Absolutely. There's been a lot of person years put into this.

ASSOCIATE MEMBER GEESMAN: This is the voice of a proud parent. (Laughter)

DR. NESBITT: No, no, we don't. Yes, it is a proud parent but no, you have to look. Even if you don't do it well, I'm joking a little bit. Even if you don't do it well you just do it approximately.

Until you can understand dispatch of tankers across the open ocean you ain't going to have a clue what that LNG is coming into Baja California for. You ain't going to have a clue whether it's going to Japan, Taiwan, Korea, China or India at $3.50. Why India at $3.50? Because the Qatarians make the same amount of money. We really care how that dispatch across the open seas goes.

And I think Catie's point is an important one. Unless you have a model. It doesn't have to be the model but a model of that dispatch, it's extremely difficult to have a heuristic model of that. It's like a heuristic model of relativity theory. I've got one but you don't want to be buying it.

MS. ELDER: By the way, my heuristic is not for sale. (Laughter) I'll give it to anybody who wants it. I was going to, I was going to comment and I almost lost it there, or lost the thought.

I did think it was kind of worth it to point out that staff has not probably been in a position until relatively recently to need to understand natural gas trading on a global level. In other words, until the advent of LNG you don't really care what's happening in Zeebrugge or you don't care what's happening at the balancing point near London. You don't care what's happening with the price of gas in Australia. But it's once LNG begins to traverse the globe that we have to pay attention to that.

So I guess I would make the suggestion or make the offer that I think they've just not had enough time to really go through that model and get comfortable with it in the same level of comfort or the same level of detail that you saw Jim Fore walk through the North American dynamics. And that I think is what led them to a place to go ahead and constrain LNG coming in to North America.

ASSOCIATE MEMBER GEESMAN: The concern I have about doing that is it is not clear to me whether it is trying to argue that water won't run downhill or that we have some type of long-term impossible to overcome permit barrier. Or that it is the equivalent of trying to build a fence along the Mexican border and think that that will stop immigration. Is this a short-term constraint? Is it a long-term or permanent constraint? We're a little bit assisted in that our forecast period is so short but it seems fairly arbitrary.

MS. ELDER: I agree with you in the sense it's an arbitrary cutoff and it is an assumption and it has to be regarded as an assumption. I know that in the discussions with staff their logic in picking the number that they picked, or the number that they picked did have logic behind it. So it's not, it's not arbitrary in the sense that they just threw a dart at the board and took the number that they hit. It's not that kind of arbitrary.

But I do agree with you, Commissioner, that I -- You know, as an economist I'd much rather understand the model economics that led me to that quantity coming to a particular location, wherever it is in the world, whether it's the US or whether it's going into Europe or whether it's

Spain or coming from Australia or even coming out of Alaska.

I'd much rather understand those economics. Or be in a position to tell you that staff had thoroughly analyzed those economics and we could tell you exactly how it worked. But I don't think they're in that position and I don't want to mischaracterize it to you.

PUC COMMISSIONER BOHN: Particularly since it's the one part of this thing that we have a little bit more marginal impact on than others in terms of creating capacity.

MS. ELDER: Yes.

ASSOCIATE MEMBER GEESMAN: I would certainly think so. And I think that the apprehension that I have is that let's say I shared Dale's conviction and there's some flat spot Nirvana out there at about $7. Why would I invest in the technologies necessary to produce gas at $7 if I had reason to believe that $4.50 LNG was out there and had been arbitrarily constrained from coming into the marketplace?

MS. ELDER: I agree with you completely there. If you're an oil and gas producer and you're looking at your options to invest your E&P

budget worldwide our, if you will, artificial constraint of LNG coming into the US is not going to change. You know, if I'm Marathon, for example, it is not going to change my investment decision. I am going to go ahead and --

ASSOCIATE MEMBER GEESMAN: So how are we going to get up to those 45,000 wells per year?

MS. ELDER: You're not. You're not, that's the bottom line.

Now there were some questions after the preliminary workshop about what the impact of less LNG coming into the US would be. And this graph I think was part of a memorandum that went to the Commissioners trying to explain the assumption that was being implemented or the constraint that was being implemented and what the impact of it would be. And this really just is a standard supply and demand curve that doesn't look nearly as attractive as Dale's I've got to say.

But if this was our supply curve initially, essentially what we have done in constraining LNG into the US at 14 billion cubic feet per day, essentially we have just moved that supply curve back. And so accordingly the price went from P1, which was in the preliminary case, to P2, now in the reference case.

Here is a graph that compares actually the prices. The pink line is the original reference case. And I just inserted a trend line to even out the ups and the downs that were caused due to lumpiness and a few other things that were going on in the model.

So if you compare that trend line to the new price forecast. Doing the trend line makes the comparison just a little bit easier on the brain. If you compare that, and I did this out to 2017, you have a price increase due to the assumed LNG constraint now of maybe about $1.50 per MMBtu.

By the way, the earlier graph in your package I think that Jim Fore used was in 2006 dollars per Mcf. I've converted everything to MMBtu. Not probably for any other good reason other than everything I do is in MMBtu. You're probably lucky I didn't go to gigajoules since I'm working on three projects in Ontario, Canada right now. But that difference there of about $1.50, $1.60 per MMBtu relates to about a three Tcf change it was in LNG.

And I've sort of skipped a point here, I'll come back to this point in a second. But we've talked about how we think that that's probably on a relatively flat part of the supply curve. I've looked at this just in 2017, I haven't looked at it in any of the other years. And it may be that in the early part of the period you are on the relatively flat part of the supply curve.

And so if you think about where natural gas prices have been for about the last three years they're all in the $7 or $8 range. I guess maybe some months have cleared in the $6s. But it seems like we've kind of gotten jaded about thinking that $7 gas or an increase from $6.10 to $7.60 wasn't very much.

And point of fact, if you actually compute the price elasticity here in 2017, in fact the price change, the percentage change in price is greater than the percentage change in supply. And so by my analysis at any rate it looks like you're actually on a relatively steep part of the supply curve.

That is to say, if I go back to the supply curve here, a curve that comes out of the union or the origin here goes, you know, directly on a 90 degree path. That would be a price elasticity of one. We've got a price elasticity that's higher than that, which implies that the curve is steeper than just this standard diagonal line would suggest.

So it may be flat in an early period but it looks like we're getting out to a place in the curve that is actually so much steeper and so we get a bigger price increase, a proportionately bigger price increase in 2017 than we did back in, than we did previously.

The other point I wanted to make is that, and we talked about this at the original workshop. One of the observations we had made was that staff actually did not prepare the electricity demand forecast for outside the WECC. They used rather the electricity demand forecast from the Altos suite of models and plugged that into NARG or had that plugged into NARG.

Now it turns out that that what that means is that you've got some things going on in the east, particularly with respect to NOx, SOx and mercury that Dale talked about. They're having an impact on the electricity demand forecast in the east.

Now one thing that this sort of brings

up the suggestion of is that in doing the next IEPR you may want to think about making sure that those two things, the WECC forecast and the nationwide forecast, are done together. Done, I don't want to say on a consistent basis necessarily, but make sure that staff is in a position to understand and be able to talk in detail about what is embedded in that electricity price forecast.

Now you have also seen two --

ASSOCIATE MEMBER GEESMAN: Catie, why would you not want to do it on a consistent basis? Is NOx and SOx and mercury somehow different in the east than it is in the west?

MS. ELDER: There are some differences, some nuances. For example, there's a cap in the east on NOx and SOx that doesn't really apply in California. I'm probably going to get the terminology wrong. There is an emissions cap and that cap isn't really relevant to California because there is so little coal in California to begin with, for example.

And I think it's the case that the new CARE caps that were implemented only apply to specific states so they wouldn't have had an impact here anyway. So there are some differences that are appropriately reflected.

The real point that I am trying to make, and I apologize for being inarticulate about it, is that because staff didn't prepare that forecast it doesn't have a really good understanding of the assumptions that are embedded in it.

And we have kind of had to go back and dig through and ask, what's really in there, what were the emissions allowance prices, for example, that come out of the analysis. How much coal was in the resource -- what is in that resource mix. You'd like to be able to know those things because I think you'd like to be able to know those things because the resource mix drives the gas demand forecast.

Now on the low side, on the low demand side that's embedded within the scenarios analysis or the scenario report you've got the 3B and the 5B cases where in essence we saw that there was a lot lower potential natural gas demand in California and the WECC due to RPS implementation and energy efficiency implementation.

Now it turns out to be the case that you've got one of those forecasts is telling you that the impact on price will be a lot, maybe 75 cents per MMBtu. The other one of those forecasts is telling you it won't be a lot.

You have also got our results. And by our results, I am throwing my lot in with the staff here. You've got staff's result that tells you that if you change supply by three Tcf the price goes up by roughly a buck. So you can use those three different things to kind of circle in and create a view about what you think is realistic.

The point I want to leave you with here is that the impact of our RPS energy efficiency and overall carbon reduction policies here in California may in fact actually lead to lower natural gas demand. And that is because coal is a very small part of the resource mix for California. And when you look WECC-wide it is not a huge part of the resource mix.

But some colleagues of mine at Beck are wandering around talking with a lot of banks in New York with some early carbon emissions work that we have done and they've got a graph in it that has -- And I wish I had a copy of it with me here to show you all.

But down this axis it lists in bars that go across the carbon emissions from every state in the union. California is about fifth smallest in terms of carbon emissions on that list. And when you look at states back east like Wyoming, West Virginia, Georgia, Alabama, the carbon emissions in California pale by comparison to the other states.

So the thought I want to leave you here with is that even though here in California and here on the west, when we implement our environmental policies we end up reducing natural gas, don't think that that's what's going to happen when this goes nationwide.

That is, we implement, if we have national carbon legislation and we try to address the carbon problem across the US, the carbon emissions levels and reduce those across the US. What's going to happen is you're going to have higher natural gas demand, not lower. So it may be lower here in the west but that result is not likely to prevail back east. And so where that leads you to is you need to spend time thinking about higher natural gas demand and the impact of higher natural gas demand on prices.

PUC COMMISSIONER BOHN: Is that a way of sort of suggesting that since coal is going to be cheaper that the prudent economic person is going to move his or her plant out of California and move it back sort of progressively eastward?

I mean, one of the issues that concerns me is the impact on the economic base of all of these things that we're doing. And it sounds a little bit like to your point exactly. The price of coal in Wyoming or West Virginia is a lot cheaper. And that is, in terms of cost, a large element in my production facility. Why on earth would I be in California?

Which gets me to the real point of my question which was, how have we integrated the projections of California's growth patterns into this? Presumably it's an iterative kind of thing. But I mean, are we projecting continual past growth rates in terms of people and business and commerce or have we dealt with that piece of the puzzle independently of all of this?

MS. ELDER: I heard a couple of questions embedded there. Let's see if I can take them apart. The California gas demand forecast that staff used has gas demand increasing, if I remember the number correctly, and it is in the executive summary of the report, by .92 percent. Does that sound right? About one percent. Just slightly less than one percent.

Within that EG demand grows by 2.4 percent. And I believe it's the case that the US gas demand increase, US gas demand is growing at roughly 2.1 or 2.4, in that range, percent. And again, the executive summary will have the exact numbers in case I goof them up here. So there is some recognition in the gas demand forecast of lower growth in gas demand here in California versus the rest of the country.

Now there is not explicitly in that demand modeling that staff has used for the reference case any change in natural gas demand due to environmental regulation. That's what gets covered in the scenarios report with the scenarios 3B and 5B and 5B+. So that analysis covers those issues rather than staff's reference case.

Now I think the thing kind of looking forward as you think about carbon legislation, federal carbon legislation, will be what kind of program is put in place for cap and trade and how high the allowance values will go. Because that's what is going to then drive the economic dispatch. That economic dispatch decision is what is going to drive natural gas demand.

At RW Beck our belief is that the allowance prices will get pushed fairly high because they should go to the value of the marginal resource that replaces coal. And if you believe that that is much higher demand for natural gas then you have much higher natural gas prices so that's going to drive the allowance value.

If instead you believe that IGCC and sequestration will become more economic than burning gas then you may not have much impact on the natural gas demand. Maybe you can solve it all with IGCC and sequestration.

Personally I think that we haven't quite proven that sequestration actually works so that makes lots of folks nervous. So the fear is -- That's why I said the thing to worry about is if you end up having to assume that natural gas is what replaces the coal in order to reduce carbon emissions then you're going to have a much higher natural gas price here.

In fact I think I'd actually refer to

the scarcity prices that Ann showed you earlier of between, was it $10 and $12 per MMBtu. That's the range that I would think of more than in the $6 to $7 that's in the staff reference case. Just kind of ballpark.

PRESIDING MEMBER PFANNENSTIEL: Catie, back to what you had said just on that. We'll see that largely in the rest of the United States. And then eventually in California? What would be the impact in California?

MS. ELDER: The link to California. I'm glad you asked that because -- I left that as an open question, didn't I?

The impact I'm talking about in terms of federal carbon legislation would likely impact the Henry Hub price. The basis differentials relative to Henry may not change all that much because those dynamics -- well, it depends I guess, actually I should say, because it's going to depend on where the higher natural gas demand occurs relative to where the gas gets produced. So you could still see some shift between the Rockies and the midwest and that sort of thing.

But by and large what I'm talking about when I talk about higher natural gas prices with a carbon emissions scenario adopted federally would be a higher Henry Hub price, which would then translate itself throughout the country. Probably with the basis differentials not much changed.

PRESIDING MEMBER PFANNENSTIEL: But they may be changed, especially for those states that have less coal use now?

MS. ELDER: That's right, that's right. And I guess to go one step further since -- I will admit I'm thinking on my feet here, which I suppose is a little dangerous. But to the extent that you have much higher natural gas demand in the east as a result from federal carbon legislation.

What that means then is that there is greater pressure on the Rockies to send that Rockies gas via the new REX pipeline, Rockies Express, we call it REX. Much more gas through REX. Potentially an expansion of REX that does impact, probably have an impact on the basis differential to California then.

So not only do we see a higher overall level of prices because they have gone up nationwide but we may in fact end up with a higher basis as well.

PRESIDING MEMBER PFANNENSTIEL: Thanks.

Other questions for Catie? Thank you very much.

Now I think this is an opportunity to get public stakeholder comments. I should ask, are there questions from the phone?

Then I don't know if there is any orchestration of stakeholder comments.

MS. WHITE: Thank you, Chairman. We have the option, if there are no more questions on the natural gas work done for the scenario and/or staff's revised assessment we can go ahead and take a short break now or just go on into the second part of the agenda related to the aging plants, if you wish.

PRESIDING MEMBER PFANNENSTIEL: Let's see. Are there any comments of further questions on the natural gas assessment?

If not I think we're all here so you might as well just continue on to the aging power plant. Mike, were you going to introduce that subject?

MS. WHITE: Commissioner, can we please take a break for just a few moments. We need to find Michael's presentation on our LAN.

PRESIDING MEMBER PFANNENSTIEL: Okay, take a five minute, a ten minute break.

MS. WHITE: Thank you.

(Off the record.)

PRESIDING MEMBER PFANNENSTIEL: Okay, I think we are ready to begin if everybody would take their seats. We've got the computer working, we have the slides and we have the telephone working so we are set to go. Dr. Jaske.

DR. JASKE: Thank you very much. For the record, Michael Jaske of the Energy Commission staff. I am going to give an introductory presentation to place sort of in context the work that Mr. Dave Larsen of Navigant Consultant is going to cover in detail. I understand we have comments from Edison and very brief comments I think also from the ISO.

I went through all of these this morning and so I'm just going to sort of make sure everyone is aware that what we're doing is talking about aging power plant retirement, replacement and transmission associated with that, done in conjunction with the scenario project.

Just to remind you of the scenarios. In particular now we're going to be focusing on the A versions of these things.

So looking at Case 1B, which is sort of compliance with current requirements so it has a mixture of current efficiency goals, current RPS requirements and some estimate of compliance with the solar initiative. Case 3A, high efficiency in California. And Case 4A, higher renewables in California. And you'll see those three scenario cases throughout my presentation and that of Mr. Larsen.

So in particular we're going to focus on the second one of these bullets where Navigant conducted extensive powerful assessments of the transmission system looking at different groupings of power plant retirements, different replacements for those retirements. Doing so in the context of each of those three scenarios that I highlighted.

And then once a set of retirements and replacements was identified those went into the analysis that Global Energy did with their production cost model then we cranked out all of the same attributes of the system as we did in the original work for the scenario project. So in effect this is a set of special cases examining different patterns of aging power plant retirement.

The original results that Global conducted and that we've presented up to this point for the scenario project assumed a 55 year service life and at that point the plant effectively disappears.

There was no specific protocol for replacing that capacity that dealt with local capacity requirements that took effect this year, calendar 2007 for entities within the ISO control area.

And the resource additions that we placed into each of the thematic scenarios were dominated by whatever is the characteristics of that scenario. And we are not in effect taking into account the whole retirement, replacement issue.

So those were the original results. I won't dwell on that.

The 2005 IEPR, just to refresh everyone's memory, included this passage which I have quoted in its entirety. And I think from the perspective of our analysis that we are presenting today we are examining the issue of the orderly retirement and repowering of the aging plants by

2012.

In our original concept of what this analysis would entail we were going to retire facilities matching the target year of 2012. We are going to look at the transmission implications of those retirements and identify upgrades and cost that out. We then rerun the production cost models and sort of determine the system, the generating system consequences of that. Report all that out.

As we got into this project we began to understand more clearly the interactions of the amount of replacement capacity as being interactive with the basic theme of the scenarios. To at least some degree the amount of thermal capacity that needs to be put in place as the old plants are retired will differ as the different resource mixes are built out through time.

We found also that retirement by the target year of 2012 creates some timing issues and it is also not compatible with the sort of slow, steady pattern of build-up of energy efficiency and renewables that are in our scenarios. So we ended up also looking at a more phased, retirement and replacement set of assumptions.

And then of course part of what we're doing here is understanding better what local capacity requirements mean and how they constrain choices.

And so at large that is what we were attempting to do. We could not do that throughout all of California since the majority of the aging plants are in the Edison service area or so-called trans area. We focused our attention there. And as I said before, we sort of placed, conducted this analysis sort of with three parallel versions looking at each of the three fundamental scenarios.

So just perhaps reiterating what I said before. Navigant Consulting, Mr. Dave Larsen as lead person, conducted this study in conjunction with the main scenario team.

We had extensive discussions about how to evolve his analysis from the more stand-alone work that we started off doing to one where it is much more integrated into the body of the scenario project. And wherever possible we're using common assumptions for the load flow analyses versus the production cost modeling.

One we had his results, as I said, we

sent them over to Global Energy. They modified their data sets and then reran the production cost model for what turns out to be six additional cases and then reported those results in the normal way that we have for all of the other scenarios. All of that is the subject of the documentation of the addendum report number two and an extensive set of appendices.

In general what we're finding is that if you put more thermal generation into the Edison service area than we had in the original scenario cases you're going to generate more within the Edison trans area and you're going to import less.

We are generally finding higher transmission costs because there are ways in which these retirements and replacement by something other than one-to-one thermal plants in the same place led to transmission system upgrades.

And of course this last point should be self-evident. If we're burning more gas in California we're creating greater GHG emissions from power plants in California. But because we're displacing imports from the rest of WECC, which have a certain element of coal, we're actually getting a net reduction in overall GHG that you could say is California's responsibility.

You'll see tables that look like this in much of the presentation and in the report. So the rows are the various cases. The current trends in Case 1, Case 1B current requirements, Case 3A high energy efficiency, Case 5A high renewables.

And then the columns. The original analysis that was reported in the June report and then the two additional columns being the 2012 retirements and the phased retirements. Those six sets of analyses being the ones that are reported in detail.

In this slide we're sort of summarizing the retirements and the replacement capacity that we had in the original analysis and that which we ended up with in the two new sets of analyses. And there are variations essentially in the amount of new thermal capacity.

That's always what new means is new thermal among the 2012 retirement versus phased retirement across the three thematic cases. We essentially need more thermal capacity in the Case 1B 2012 retirements than you do down in the lower right corner where we have high renewables and phased retirements that allow those to sort of be in sync.

This is just a snapshot of the overall aggregated transmission costs that we found by 2020. There is a much more complicated table that shows various projects and the timing of those projects that these are sort of the cumulative column totals, if you will, of the more detailed chart in the report. It does show something on the order of $700, $800 million difference from the Case 1B original all the way over to Phased Case 4A. So there is a consequence to the transmission system of this analysis.

I think I have basically already made this point. That by putting more thermal generation into the Edison area imports decrease, exports increase and there's a net decrease in imports. And that always is the case across all these scenarios, or variance of the scenarios.

This is the GHG consequence that I mentioned in sort of summary form before. The table is organized the same way as before. For Case 1B there are two sub-rows, GHG emissions just from California plants or GHG emissions from all of the plants for which California load is served.

So those would be those within the state, the so-called remote plants like IPP, and then the short-term purchases. So those three components are in California responsibility.

You see a very slight increase in the 2012 retirement and phased retirement compared to the original. Something on the order of 1700 tons per year. Similar small increases in each instance for the other three scenarios.

And then as I indicated before, if you compare the California responsibility rows, very slight decreases relative to the original. So modest changes in these results.

I think I've already essentially mentioned this.

We've had some limited interaction with the ISO and Edison about this analysis.

We met with the ISO around March and they gave us some good pointers about how to modify the contingency assessment to make it better match what the ISO is doing with LCR studies. And in the detailed documentation that Navigant has in the appendices there is sort of a chronology of how the analysis evolved as we reacted to this advice from the ISO.

We also got some limited input from the Edison transmission planning folks who wanted us to use updated line ratings, which in general are lower line ratings. And everything else being equal, increases the odds that transmission lines will be found to be overloaded and therefore mitigation needed.

And they also were helpful in providing some idea about what the limiting element on lines were. Because the data we were working from frequently showed what could be perceived as inconsistencies between the conductor on various lines and what Edison had as ratings. It turns out that various terminal equipment, you know, can be different between the two lines. Which turns out that those things are the limiting elements on the lines.

Both Edison and the ISO have reviewed a draft of the report. We wanted to be sure that we were not making some major mistake before we presented it in public. We got feedback from both of them and incorporated that mostly in an editorial and a little bit of embellishment on caveats. I believe both Edison and the ISO are going to speak today so they can speak for themselves about the merits of the study.

So staff believes that this work is a credible start to what is turning out be an even more complicated topic than we thought before we went into this.

As in any sort of what if scenario assessment kind of project the results we're getting are conditional. Because we are saying, analyzing, you know, what if we have high efficiency or what if we have high renewables. We have some sense of the consequences of that to the decision-makers, yourselves included, to make all the policy calls that will turn what ifs into realities.

We think that there is more analysis of this subject that is required. The ISO has put out a proposal for a broadly based transmission study plan that would focus on this question of retirements. That may be a forum in which the next steps in this whole chain of analysis will take place.

Given that we're frankly reporting to you here that the Energy Commission's 2005 IEPR policy is still in the throes of being looked at and examined and analyzed, and there's yet more analysis to be done. You are going to need to consider how to energize staff, other institutions, stakeholders, to sort of get focused on this question and move through analysis towards some sort of action.

And with that I am going to stop and Mr. Dave Larsen is going to do his presentation.

ASSOCIATE MEMBER GEESMAN: Mike, before we go a couple of questions.

DR. JASKE: Yes sir.

ASSOCIATE MEMBER GEESMAN: The chart you showed with the transmission costs. You drew a comparison diagonally from the original case in I think scenario 1B to the phased retirement case in Case 4A. Isn't the more pertinent comparison the horizontal cost comparison within the same scenario? It looks to me consistently that the retirement program, were it to focus on 2012 or 2029, would add about $329 million of additional transmission costs.

DR. JASKE: Yes, I think that -- I should probably have decomposed it into the two steps. You're focusing on the horizontal. On could say that Case 1B is sort of where we are today. So if you go down then you have about a

$500 million increase.

ASSOCIATE MEMBER GEESMAN: Right, but that's based on the differences in those scenarios, not based on the retirement program.

DR. JASKE: Yes, sir, that is correct.

ASSOCIATE MEMBER GEESMAN: And you seem to infer that the rationale for the phased retirement, slipping the date back from 2012 to 2020 was a potential conflict with the state's policies regarding efficiency and renewables. Would you elaborate more on that.

DR. JASKE: If I gave that impression by attempting to go through this quickly and to paraphrase what is in the report I apologize. That is not the right conclusion.

The right conclusion is that the analysis shows if we focus the bulk of the retirements in 2012 that because efficiency or because renewables in the patterns assumed in the scenario project, we have to add thermal capacity in order to reliably serve load in 2012.

That is not needed as you get to the outer year, the 2020 period, because the efficiency or the renewables in either case has built up and altered the need for that thermal capacity.

So a phased variant in effect says, let's slow down the retirement to match up to the assumptions of the scenario project as they were developed in the spring and reported previously in these events.

What the report then goes on to say is, one could conceive of accelerating that efficiency development or that renewable development and you would get a different phased retirement pattern that would match.

So the point I think is that there are economies in the transmission system in the entirety of the angst of licensing and constructing power plants that can be minimized by sinking the retirement with the replacement strategy, whatever that replacement strategy emphasizes.

And those of you familiar with these cases, if we had had more time we could have done a 5A. We could have combined efficiency and renewables and had yet a different result to some degree. We just simply ran out of time to do that.

PRESIDING MEMBER PFANNENSTIEL: Mike,

would it have been a whole new level of complexity on the high renewables case to think about how many of these megawatts must be wanted just for firming up the renewables? I doubt that you did that but it strikes me that is worth -- If we're looking at high levels of renewables and retirements some of those older plants we may want to hang on to for the very reason of having them there to firm up renewables. Was that considered?

DR. JASKE: No. That is yet another illustration of how this set of products that we're publishing here is only a step in the direction of looking at this whole issue.

Many of those older power plants in effect are operating in the capacity factor of a modern peaker and could in effect be thought of as equivalent to a modern peaker. And if they're cheaper than a modern peaker why wouldn't one just keep one.

They may in fact have other advantages. In fact I believe Edison's presentation gets into this, just in a very cursory way but helpful to remind us that there are other elements to transmission and system stability analysis that we did not conduct. And that there may in fact be superior qualities in some of those old plant in terms of rotating inertia and helping stabilize frequency and other sort of nuances of the electrical system.

And those may well be very legitimate things to look at in the detail that Edison seems to be suggesting.

Are there other questions? Okay, Mr. Dave Larsen. He is going to sit up here and I am going to do his slides for him.

MR. LARSEN: As Mike mentioned in the first two slides we've got -- Thank you.

The first two slides in the package we put together for this presentation kind of reinforce what Mike just mentioned. The purpose of the original aging plant study, to develop an understanding of the implications of retiring certain of those aged plants. I won't spend a lot of time on the first two slides because it kind of reiterates what Mike has already said.

What I want to do is just, right now -- Let's go to the third slide, Mike, if you would. And I apologize for the quality of the map. The map that I have for the Edison transmission system I've been hauling around for a number of years and it's getting pretty beat up.

ASSOCIATE MEMBER GEESMAN: So are these plants.

MR. LARSEN: The red star by it doesn't really mean anything negative, it's just a way to make them stand out. But just to get you orientated. I'm sure most of you folks are aware of where those what we've called the aged plants for the purposes of this study are. But the two that are up in the northern, the northwestern part of the Edison system up at Mandalay and Ormond Beach up in Ventura County.

There's four what we call coastal plants. From north to south they're El Segundo, Redondo Beach, Alamitos and Huntington Beach And then kind of an interior plant that's in the San Bernardino area, it's Mountain Vista power project. Sometimes called Etiwanda in the old, before they were all bought out by other folks.

The major areas of discussion that I wanted to talk about today, and Mike alluded to it earlier, is as we've gone through this process over the last nine to ten months now we have moved from one phase I guess you might say, of understanding the problem to additional phases.

And those are kind of what I want to talk about, some of the results of them.

I'll talk about some of the initial power flow studies we did back in the -- early this year and they're talked about in the report that we issued on April 1st. It's in the appendix.

Because of some feedback that we'd gotten from Edison on readings and some of the work that had transpired as far as what the staff and GED were doing as far as the scenarios project we developed some cases with different levels of renewables, modeled them.

And then we subsequently learned that maybe, at least based on this analysis, that retiring all that generation in 2012 might not be the best thing to do. You might want to phase it out. So we'll talk a little bit about how we got to that point. And I think it will get to your question somewhat, Mr. Geesman. I don't --

ASSOCIATE MEMBER GEESMAN: When you do that I want you to remember, this is a problem we identified first in our 2004 IEPR update. We reiterated it and emphasized it quite a bit in 2005. So you ought to assume when you're addressing us on the question of rolling it out 2012, which frankly seemed like a pretty leisurely timetable back in 2005, out to 2020 is going to require a fair amount of elaboration to fully get your point across.

MR. LARSEN: Okay, we'll work on that, sir.

What we also want to do is just briefly talk about a preliminary assessment and some of the local capacity requirement issues that Mike had alluded to. Talk a little bit about the coordination we've had with some of the other parties, Edison and the ISO. And then quickly go through the conclusions as we see them from the study.

The initial case that we developed was for the initial 2012 case. A little bit of particulars about what we did on that case. We started with the WECC base case for 2016 and modified it. At the time we started to work that seemed to be about the best one that was publicly available to us.

But we did go and modify that case fairly substantially to reflect loads, 1-in-10 peak load conditions based on information that was in Commission staff's June 2006 load forecast. We needed that for the whole state.

As far as the Edison area was concerned that's where the focus was. We allocated that total Edison load for the forecast to the different load busses in the Edison system based on information that was in Edison's most recent ten year plan at that time.

And then we modeled the new renewable resources. At the time we were just picking up on the wind and the biomass but generally at the levels that were in the Case 1B that Mr. Jaske alluded to earlier.

Other modifications to the case, just to get it up to speed, were to include several transmission projects that are proposed. There's maybe one or two of them that the schedule may have changed a little bit since we started this work but they're still in there.

Basically we included the Tehachapi Renewable Transmission Project and all the facilities that it entails. The Harquahala-Devers 500 kV line, sometimes Palo Verde Devers number 2. A second line from Devers to Valley on into towards the LA Basin, a second 500 kV line. And then the Sunrise Power Project that San Diego Gas and Electric has proposed to build between the Imperial Valley and San Diego.

Also at that time there were three projects that we were aware of that Edison had announced that it had entered into purchase power agreements for a period of years so we included those as part of the existing resource mix, if you will.

Those were some peaking capacity at Long Beach and out in the Devers area. The first project is like 260 megawatts and 450 megawatts peaking out in the Devers area and then a 490 megawatt combined cycle project in the Blythe area that we added to the case and kind of, at least initially, treated those as, if you will, existing projects.

Finally, and to fill the gaps in as we found them for serving loads, making up resources that were lost if some of the aging plants were retired and so forth. We based those decisions and the locations of those resources on information that was in either the California ISO's generation interconnection queue as of the time we started the study or the most recent version of Edison's wholesale distribution access tariff, which also deals with generation interconnection on the Edison system that is not under the operational control of the ISO.

As we mention on the next slide, on number eight then, the 2012 case, the way we had it set up, modeled a little less than 5,000 megawatts of aged power plants in the LA Basin. And they're kind of listed here just for your information. There's six units at Alamitos with well over 1900 megawatts of capacity.

There were two units at the Huntington Beach facility that are considered aged. There's also two units there that were retrofitted within the last four or five years that are not included in that category. So I just ask you to keep that in mind.

There were four units at Redondo Beach, two units at El Segundo plant and then two units at the -- I call it Etiwanda here. It just reflects my -- it's basically the plant in the San Bernardino area.

With regards to the Ventura County area. The case modeled two units at Ormond Beach, each about 700 megawatts with a combined capacity of

1400. And then two units with a combined capacity of 400 megawatts at Mandalay.

Once we got the 2012 case put together then we moved on to develop cases for 2016 and 2020. those were primarily done just to assess what the impacts of load growth on the Edison system would have to some of the results that had come out of the 2012 studies.

As was the case with the previous work they also reflected loads for California based on the Commission's June 2006 forecast and modeled the renewable resources, the wind and biomass, based on the levels in the scenario 1B case.

In addition the 2016 and the 2020 cases also modeled the proposed Green Path Project that Los Angeles Department of Water and Power has proposed between the Imperial Valley and the Los Angeles Department of Water and Power system.

And again we relied on the ISO's interconnection queue and/or Edison's interconnection queue for the resources that we had to add to the system to make up because of load growth or retired facilities.

The next slide then basically just kind of pictorially shows the resource stacks for each of those initial base cases I just talked about. From Imports down through the New Thermal resource all the way down to the very bottom which is pretty flat. It would be the hydroelectric generation on the Edison system.

And you can see the only place between these cases where we have significant changes are between the New Thermal resources, it would be the second block down, and the New Renewables. There's some growth going on there to accommodate primarily load growth on the system.

Once we got the base cases developed then we kind of went back and based on -- started our studies on the 2012 case. We tried to identify how much aged plant generation could potentially be removed from the system without causing what we call adverse impacts on the transmission system. When you start having different contingency conditions on the transmission system itself.

And then assess the, as I mentioned earlier, assess the impacts of load growth on the findings of the 2012 case using the other two cases that we developed. The impact --

ASSOCIATE MEMBER GEESMAN: Now when you

speak of --

MR. LARSEN: Excuse me.

ASSOCIATE MEMBER GEESMAN: -- removed did you consider repowering at the same location?

MR. LARSEN: No we didn't.

ASSOCIATE MEMBER GEESMAN: Was there a reason for that?

MR. LARSEN: It was primarily just to see kind of a worst-case, call it a worst-case scenario that if you did not repower and develop new generation elsewhere on this Edison system what might be the impacts to the transmission grid.

ASSOCIATE MEMBER GEESMAN: So where a guy like El Segundo, which has gone to this Commission and gotten a permit, a heavily contested permit but a permit nevertheless to repower, you just ignored that?

MR. LARSEN: Yes, generally speaking. We also, just to make sure that I'm clear. There are other projects that are in the ISO's interconnection queue down in, more down along the coast that we did not include in the analysis either. And again like I say, this was just kind of really to stress out the system to find out where the problems might be if that in fact were to happen. I will get back to one point that you made a little bit later in my presentation.

Basically what we do, it's kind of a typical method of doing, assessing impacts on the system, is run basically a powerful model that simulates a bunch of contingencies on the system. Transmission lines being forced out of service for whatever reason.

We looked at, there's basically two levels on what they call the N line. An L-1 is when a single line is forced out, or a contingency C condition, L-2, where you have two lines out. On pretty much all of the 230 and 500 kV lines in the Southern California Edison area we did those studies on pretty much all the existing generation in the basin other than the eight plants we retired.

And to kind of give an idea of some worst-case impacts, again, we also simulated them all with one of the San Onofre generators out of service. So you take about 1,000-plus megawatts out of service, the thing is down for maintenance or has a problem or whatever, to kind of give an idea of what impact that would have.

We also tried to get back to some of the LCR, local capacity requirement, work that the ISO has done. What some folks would call overlapping outages. In other words, if you have a transmission line that is forced out of service and is in the process of being repaired and you have a second line happen, pardon me, get forced out of service, then what you have to have available to give yourself some sufficient operating coverage.

Unfortunately that tends to be almost an endless possibility of things you can come up with so just because of time constraints and so forth, and budget constraints, we kind of limited that portion of our analysis. But I expect that would be one thing that this work that the ISO is proposing to start shortly would probably be a fairly extensive effort on that.

Finally as far as the approach in the initial studies. Like I said, we identified the overloads and then identified potential methods of mitigating them. And we also just took a kind of a sensitivity case that I'll talk about towards a little bit where we said, what happens if you take out all of the aged generation in 2012 as far as system impacts and so forth.

As far as the 2012 cases then. Our initial studies indicated that you could retire a little over 2300 megawatts in the LA Basin generation if you reconductored a portion of one line out in the Mira Loma area, replaced some wave traps on another line down along the Redondo Beach area. And it's something that Edison had proposed to do in its ten year plan. And then reconductored another fairly critical line that's approximately 13 miles in length.

That's one part of the picture. Another key part of the overall picture is you also have to provide, if you will, a little over 3500 megawatts of replacement resources to replace the capacity you've lost and give yourself some coverage if you got that capacity retired and you have a forced outage of one of the SONGS units and then because of some increased losses on the system.

So looking at it from the transmission perspective is one part of it. But looking at it from the need to develop replacement resources, the timing and so forth, the requirement to do that is another perspective.

Excuse me. With regards to Ventura County our studies indicated that basically all of the aged plant generation in Ventura County could be retired if there were certain things that were done. Probably the most important of which, well two of them that are really important. The Antelope-Pardee line, which is planned to be built as part of the Tehachapi Project was in service.

There were some limiting elements that Dr. Jaske alluded to earlier when the Pardee-Moorpark lines were upgraded. And again, you had replacement capacity available to cover yourself for removing that 1800 megawatts of capacity. So it's kind of a two-pronged approach. You've got to look at the transmission side and then also on the replacement side.

ASSOCIATE MEMBER GEESMAN: And once again, did you consider repowering at that specific facility?

MR. LARSEN: No, no. It's certainly an option, it just wasn't --

ASSOCIATE MEMBER GEESMAN: Wouldn't it appear to be a logical if not a preferred option if you're concerned about transmission impacts?

MR. LARSEN: It would certainly be an

option that's for sure, yes. You know, obviously there's -- And you alluded to it earlier. There will be siting issues, environmental issues with just about anything you do.

As far as the -- Just to kind of summarize here as far as what we assumed would be retired. We assumed that -- We found that 980 megawatts, basically the four smaller of six units at Alamitos could be retired. We could retire two of the four units at Huntington Beach, the aged units. And 340 megawatts, the two smaller units at Redondo Beach, and then the generation out at the Etiwanda plant out in San Bernardino. Both those units could be retired.

And I mentioned earlier but we basically had found based on our assumptions and so forth at the time that the generation up in Ventura County could be retired.

As far as replacement capacity. Here again this is where we based our assumptions about what might be available on information that was in the generation interconnection queues. There was about a little over 4,000 megawatts of thermal generation that was added within the main SCE grid. That would be down basically in the eastern portion of the Los Angeles Basin, if you will.

A little over 1100 megawatts up at the Mojave/El Dorado substations in Southern Nevada. There is already some generation interconnected. And then we had increased imports from Arizona slightly. In the one case just to give ourselves a little bit of, to cover all the deficits we had.

The next slide then kind of pictorially shows where we found problems on the system in those initial 2012 cases. There's overloads over in the eastern part of the main Edison system down in the lower Chino area. An overload down towards the Huntington Beach. Kind of highlighted in red. Some in the Redondo Beach area. Then the Pardee to Moorpark lines up in the northwest part of the, the northwest part of the system.

Those were the facilities that we noted. And of course this chart doesn't reflect anything that's been mitigated. It's just kind of where we saw the problems.

As far as the 2016 cases then. Not surprisingly that again based on the assumptions that we made that because of load growth on the Edison system the impacts that would be noted on the transmission system were more severe in 2016 than they were in 2012.

And basically that would -- at least at the time, mitigating those overloads would require reconductoring both the -- two of the three Chino to Mira Loma lines, about 15 miles total length. And then try to figure out some way to mitigate some small overloads we saw down in the southern end of the system.

We also noted that there were overloads occurring on some of the 230 kV facilities of Edison's out in the High Desert area on Pisgah substation, the Barstow area. Those were primarily due to the assumption that new renewable generation would be interconnected at that location and it seemed to be kind of insensitive of whether the aged plants were retired or not. But I just pointed that out as a finding.

For the 2020 case pretty much the same thing. Again with the 4140 megawatts of retirements load growth on the Edison system would cause additional overloads on the system and require mitigation.

What we did, assumed on mitigating the impacts we saw up in the Ventura County area was assume that the Antelope-Pardee line, the one that

I mentioned earlier that's planned to be built as part of the Tehachapi project and is going to be designed for an operating voltage of 500 kV, would be converted and start operating it at 500. So you have to obviously install some substation facilities. But that would occur.

The one of the existing lines from Vincent over towards Santa Clara would be looped into Pardee. And then a portion of that line between Vincent-Pardee could also begin operation at 500. It was originally designed for 500 kV so they could do some substation modifications and convert that line to a higher, operating at a higher voltage.

And then reconductoring a few miles of line down in the southern portion of the system, the Edison system.

And doing some work on the series capacitors on the El Dorado-Lugo 500 kV line. That's basically because the assumption we made at the 2020 time frame that some of the replacement capacity would be renewable. Not renewables but thermal capacity up in Southern Nevada, based on the load conditions that we were studying at that time.

The next chart, the picture kind of depicts by 2020 where we had seen the problems. Where we had seen the overloads on the Edison system.

ASSOCIATE MEMBER GEESMAN: And again, even by 2020 we haven't repowered any of these sites?

MR. LARSEN: No. You can see a lot of them are ones that we -- are obviously ones that have popped up before but we're starting to see some new ones up between Pardee and the Sylmar area. Some over in the Serrano area, Villa Park area and so forth. And then one or two more over in the Chino area.

Once we completed that then it took -- I mentioned earlier we looked at the impacts if you were to retire basically almost 7,000 megawatts of aged plant generation down in the LA basin by 2012. And as one would expect, and we found not surprisingly, it would have some fairly significant impacts on the transmission system.

You'd need to reconductor several more miles of line, approximately 30 miles of line.

You'd have to do some upgrades on three other 230 kV lines.

And you'd have to install a substantial amount of reactive support to provide voltage support down in the Edison, down the Edison area.

Again another major finding. Again, we did not -- In this case we did not assume that any of that generation could be repowered so you had to come up -- it would have to be about 8,000 megawatts replacement capacity provided either through repowering or new generation to come up, to allow that aged plant generation to be retired and to provide some backup capacity in case of outage of one of the San Onofre units.

ASSOCIATE MEMBER GEESMAN: And you didn't factor in any distributed generation or industrial combined heat and power?

MR. LARSEN: Nothing other than some -- Not of that nature, no sir.

ASSOCIATE MEMBER GEESMAN: And what about the BP Carson project at the BP refinery?

MR. LARSEN: That was not included.

ASSOCIATE MEMBER GEESMAN: Okay.

MR. LARSEN: Obviously, and I kind of summarize I believe in this last bullet here on page 23. Because of the lead time and cost required to plan, permit and develop replacement capacity and transmission upgrades you obviously have some pretty serious problems by trying retire all that generation down in that portion of the system by 2012. Just because of the impacts on the system and having to come up with replacement capacity.

Again I tried to show that pictorially on the next slide. Just to kind of give you an idea of how the entire last 2000 megawatts of capacity affects the system.

You still the problems on Pardee to Moorpark but now you're starting to see a lot of problems south of the Mesa substation down towards that part of the LA Basin. You see a lot of overloads from Serrano down towards Santiago substation in the southeastern portion, that portion of the Edison system. Then again the overloads out at Chino and Mira Loma.

And like I said, all those studies were done just basically assuming that the replacement, the replacement capacity would be brought in from outside, if you will.

ASSOCIATE MEMBER GEESMAN: And why is that a logical assumption?

MR. LARSEN: We primarily did it to look

at a worst-case type assessment, if you would, sir. That's logical, that's the reason we did it.

ASSOCIATE MEMBER GEESMAN: So you think that's what you captured here.

MR. LARSEN: Yes, I believe so.

ASSOCIATE MEMBER GEESMAN: It doesn't get any worse than this.

MR. LARSEN: The only -- Well, it probably could if, for example, say the load forecasts were different. Yes, it can get worse than that because --

ASSOCIATE MEMBER GEESMAN: That would take another study though.

MR. LARSEN: No, no, I think we already -- what I was going to say why it could get worse than that was, and Dr. Jaske alluded to it earlier and I'll talk about it here in a minute.

By the time, by the time we finished up this phase of the work and had talked to the ISO about it is when we found out that because of a lot of reasons having to do with NERC guidelines and so forth that Edison had rerated quite a number of their 230 kV lines. In other words if a line, for example, was good for 3,000 amps when we did the first work, it might only be for 2500 now, you know, with the rerate. So that kind of threw another, another wrinkle in the works.

PUC COMMISSIONER BOHN: Can I ask a question just out of curiosity.

MR. LARSEN: Sure.

PUC COMMISSIONER BOHN: What was the task of the study? It sounds a lot like the task was to create, as you said in your words, a worst-case scenario without applying any judgment as to gradations of worst-case or anything like that.

And I guess my question is, one can posit a whole series of worst-case scenarios and wring our hands. I don't know what you'd do with that kind of a study in terms of policy initiatives. And I just want to be clear in my own mind. Your task as you saw it was to tell us how bad it could get.

MR. LARSEN: No sir.

PUC COMMISSIONER BOHN: But not tell us a cost-effective way to deal with the optimal retirement schedule.

MR. LARSEN: No sir. Our task was to identify the best we could how much generation we thought could be retired, removed from service in the Los Angeles Basin.

ASSOCIATE MEMBER GEESMAN: Using the dumbest possible replacement strategy in doing that.

MR. LARSEN: That could be. Maybe it is, but I think it gives you, it gives the Commission and other folks some guidance perhaps or some insight as to what might happen if --

ASSOCIATE MEMBER GEESMAN: We take a really stupid approach.

MR. LARSEN: I wasn't going to say that. I was going to say, if generation is not built down along the coast for whatever reason. So I think from that perspective it -- And that's what I meant when I said a worst case, sir. If I misled you I apologize. The primary goal was to see what could be retired and what would be the impacts of doing that.

And I think once we talk about it a little bit more then perhaps that will hopefully become a little more clear. And I guess maybe the worst-case thing probably reflects my too many years of doing transmission planning. You tend to, you know, tend to look at the worst-case scenario just to make sure you've got yourself covered.

In any event I mentioned a few minutes ago that after we completed that initial work in the April time frame we found out that Edison had rerated quite a number of the 230 kV lines on the Edison system.

And also by that time Energy Commission staff had worked their way further through some of the scenarios that Dr. Jaske had talked about earlier where we were looking at higher levels of energy efficiency and higher levels of renewable resources than we had assumed when we did that initial work.

So basically what we did as a result of that was go through and prepare some updated base cases for those three study years for the three basic scenarios that Dr. Jaske alluded to earlier, the 1B, the 3A and the 4A cases. Just to see if you start bringing in more renewables, higher energy efficiency, what does that do as far as the impacts on retirements replacement capacity, things like that.

The next page just is a kind of a summary of what we had assumed in the studies as far as the various levels of renewables and energy efficiency. PV solar. Again that was pretty much all based on the work, information that was prepared by Commission staff as to what amount of capacity would be available in those years.

The numbers that I have summarized on this table are dependable capacity rather than installed capacity. So in the case of the wind capacity in Case 1B in 2020, that's probably -- the actual installed capacity would probably be four times that much. Maybe higher than that. They reflect the dependable capacity rather than installed capacity for the wind and solar and those type of resources.

But it kind of gives you an idea of the range of numbers that we were looking at in those cases and variations between the different types of resources.

The next slide then just talks a little more about how we modeled and where we modeled them, if you will. And again these numbers are dependable capacity. So with regards to the energy efficiency numbers or values, we assumed that the load across the entire Edison system would be reduced pro rata to reflect the impacts of those energy efficiency measures being taken.

As far as the solar PV resources. Based

on what we had assumed on some work that was going on with the intermittency project at the time where they had identified a number of busses on the system where they thought PV solar could be installed. So we basically just utilized that type of information.

As far as the concentrating solar we pretty much based that on information that was on projects who had filed interconnection applications with the ISO and scaled them to kind of give some regional coverage to them if you will. But the bottom line numbers, the totals, are all based on information that was derived as part of the scenarios project.

The next page just talks about what I've already said. What we had done as far as the energy efficiency, the PV resources. Biomass. We also used information from the Intermittency Analysis Project to locate those on the system.

The dependable capacity of solar, the concentrating solar, was assumed to be 87 percent of the installed capacity.

As far as the wind we assumed a 22 percent value for the wind in the Tehachapi area based on review of some historical information from the Commission.

We used a slightly higher percentage of that in the other portions of the Edison system but it is still fairly -- may develop into the load level.

And I talked a few minutes ago about when we were looking at the solar and the wind, how we determined which portion of the system we would model it in as reflected in that previous table.

The next slide is just kind of, again, a summary. It kind of shows the stack of resources for the three study years we did for Case 1B. We've compared here against what I call the 2012 reference case, which is basically 2012 with basically no new renewables and all of the aged plant generation on line.

So you kind of compare and see how as you go out in time the energy efficiency and photovoltaic increased the topmost piece of the chart. The other new renewables, how they increased. The second piece down. How we've had to increase what I call the queued thermal generation, the assumed replacement capacity, and then the change in aged plants between those different scenarios.

The next slide then is kind of a, I tried to show in a different format, I guess you will, what we had shown in the previous one. In other words, starting off in 2012 the reference case and then retiring all of the generation by 2012. Kind of the golden line that goes down through the chart.

The thermal capacity is the green line that heads up. Once you get to the point of 2012 we've had to install about 6400 megawatts of assumed thermal replacement capacity.

And then the bottom two lines show the -- kind of the coral colored line is the energy efficiency, the PV, and then the other renewables, the wind, the solar and so forth, the biomass, are included in that blue line at the bottom.

So just kind of a different way of picturing the resource staff, if you will, so you can see what's happening.

The one thing we did do on this chart, and it becomes more obvious on one later on, but we did also look at the level of installed thermal generation from two perspectives. One of which is the upper blue, is what we had to install. And there a lot of times it's based on the first year, you have to install it. The second line then is what would be required for dispatch to meet your peak load in that year. At least based on our way of doing it, what you would have to do as far as that capacity.

As you can see in Case 1B there is some, for lack of a better term, you might call stranded capacity in 2016. The next slide then is Case 3A. We're just looking at --

ASSOCIATE MEMBER GEESMAN: So what type of thermal was that?

MR. LARSEN: It was a mix of combined cycle plants and peaking plants. About a 50/50 mix.

ASSOCIATE MEMBER GEESMAN: And how did you determine what the mix would be?

MR. LARSEN: We based it pretty much, just based that on what had been, was in the ISO's interconnection queue at the time.

ASSOCIATE MEMBER GEESMAN: So it's whatever the developer wanted in terms of the assumed capacity factor?

MR. LARSEN: Yes sir. We didn't get involved in the capacity factor. We were just basically looking at peak megawatts. But it was, you know, like I said, it was based on what was in the ISO's queue at the time just to allow us information on what to assume is capacity and potential interconnection points for it.

ASSOCIATE MEMBER GEESMAN: Okay.

MR. LARSEN: That was the only magic to it. Case 3A then is the next, the next picture. Again just a resource stack, how things change. Here again this case has considerably levels of energy efficiency than the other case so it has some different impacts on the system. Mainly because we have reduced the load throughout the Edison system, including the LA Basin and Ventura County. So they'll have a little different impact on the system.

Again going to the next chart. You can see pretty much similar to the one I had shown you previously except the energy efficiency and photovoltaic capacities that have been installed are soon to become available. It has increased considerably by 2020. In 2016 you start to see your wider gap, if you will, between the installed thermal capacity and to pretty much install to meet the requirements in 2012 and what conceptually would be dispatched to serve the load.

The next slide then is the resource stack for Case 4A. This is considerably higher levels of new renewables than some of the other cases and slightly lower energy efficiency than the 3A case.

And again the chart on page 35 that shows when you start stacking all these assumed resources how the requirement for thermal capacity that you installed in 2012 drops off by 2016 and 2020 because of increases in renewable generation and energy efficiency.

ASSOCIATE MEMBER GEESMAN: And again, that's defining the thermal plants just based on the snapshot you took of the ISO queue?

MR. LARSEN: Yes sir, yes sir.

ASSOCIATE MEMBER GEESMAN: So that too is kind of a dumb mix. There is no intention to optimize that particular mix of thermal facilities either by location or design type.

MR. LARSEN: Well, not so much by location. I said earlier -- I suppose regardless of what we would have done somebody would said it was dumb so -- We based it on what was in the

ISO's queue as far as the interconnection because that's where people say they want to build plants.

As far as the resource mix. On some of these cases in the initial years they were pretty much 50/50 combined cycle and peakers, just because that happened to be the approximate mix of what was in the queue at the time. Some of the later, other cases where we were -- not so much here but when we talk about the phased retirements. We tended a little more toward the peaking-type scenario rather than too much combined cycle. Generally speaking they were almost 50/50 in these two cases.

As far as results are concerned, somewhat different than the initial stuff that we, results that we talked about. Not surprisingly because of the changes in the ratings on the 230 kV lines. On some of them you see more overloads occurring based on the scenarios that we ran.

For example for Cases 1B, 3A and 4A, that's pretty much all of the major scenarios, we found that you'd have to see overloads on two of the lines from Chino to Mira Loma and the Barre-Ellis line. Then of course the Moorpark-Pardee line.

There are also for Case 1B where you had fairly low levels of energy efficiency and loads in the Edison area were higher than they were in the other cases. I saw some overloads on two other, basically four other lines on the Edison system.

What we did after identifying those overloads and based on information that Edison had provided and Dr. Jaske alluded to earlier as far as what the constraining, limiting problem if you will, on the Edison system, is went through and developed some estimated costs to mitigate the different problems. Overloads and so forth that we had seen.

And because the number of overloads and things requiring mitigation are almost the same between all three of those cases there is not any difference in what the estimated cost to mitigate. You know, by 2020 we're looking at $190 million approximately based on the findings of our work. Granted if you assume something different as far as resource location, particularly I suppose --

ASSOCIATE MEMBER GEESMAN: If I moved the plants around it would make the numbers change.

MR. LARSEN: I think where you primarily see it, Commissioner Geesman, is if you were to assume that more of the aged plants were retired -- pardon me, repowered, or new generation was built down along the coast.

ASSOCIATE MEMBER GEESMAN: If I assumed that a permit that this Commission struggled for years to issue actually resulted in a project being constructed on the El Segundo site I'd probably change these numbers a bit.

MR. LARSEN: You probably would sir, yes.

In addition to the overloads that we noted on the main portion of the 230 system of Edison in these studies we also noted some other ones on the system more out in the desert area between Southern Nevada and Lugo substation, the Victorville area. And those are listed here but they're pretty much due to the assumed development of renewable resources on that portion of the Edison system. They really don't have much to do with the fact that we assume generation being retired.

That kind of brought us to the next level of effort where we looked at, is there a way that you could phase the retirement of that generation such that you would minimize or negate, if you will, some of the under-utilized capacity impacts that we'd seen in some of the previous work. So basically what we did was look at the results of the previous analysis.

For Cases 1B and 3A we deferred the retirement of both the Huntington Beach units and one unit at Mandalay for a year based on the information we were finding.

For Case 4A where you've got a fairly high level of renewables and fairly high levels of energy efficiency you'd conceptually defer retirement of several hundred megawatts of generation for some period of time. For example Ormond Beach, defer that to 2015. The Mandalay units from 2012 to 2016. One of the Huntington Beach units out to 2016 and then the other Huntington Beach unit almost out to the end of the study period, to 2018.

It gets back to what Dr. Jaske was talking about previously that because of the estimated impacts of new renewables coming on line, energy efficiency impacts and so forth that it can allow you to at least conceptually shift that retirement schedule around quite a bit.

And that's kind of what I tried to show on the next, on the next slide here. If you recall on the original Case 4A we talked about there were some instances in the 2016 and 2020 time frame where some of the thermal capacity that we had assumed would be installed in 2012 was not being utilized. In this case it's pretty much all being utilized. So we have essentially -- I think it's about 1700 megawatts of reduced thermal capacity you could provide, if you will, by just adjusting the potential retirement schedule to reflect other changes on the system.

Briefly then, the studies on the phased retirement cases indicated that several of the elements that the need the upgrade them could be deferred for at least a year, perhaps two years, and some perhaps to the end of the study period depending upon what was the situation with certain generators.

For example the Barre-Ellis line could be deferred for about four years for cases 1B and 3A and all the way to the end of the study period for Case 4A when you've got a lot of energy efficiency and a lot of renewables coming on the system.

I talk about that a little bit more on the next slide. Early on I mentioned the fact about Huntington Beach. The fact that there's four units there too which are considered aged. Back to your question earlier, Commissioner Geesman. That particular facility seemed to be very critical in some of the overloads we'll see whether or not the generation at that location is retired has a fairly significant impact on the 230 kV lines from the eastern portion of the LA system on into the coastal areas, if you will.

So one option rather than retiring the two units at Huntington Beach might be to not retire them. Just leave them running and see how to repower them. Or developing some new generation in that same general area that, you know, almost from an electrical perspective meet the same needs as Huntington Beach but might be at a different site. But it probably has to be physically fairly close to that area.

That pretty well, as far as the work that we have done on the aged plant. That kind of summarizes where things are as far as what we found. I'll talk about some conclusions later.

We also did a quick look at the potential impacts on local capacity requirement. You know, if the aged generation was retired and was replaced by generation elsewhere, if you will.

The information on slide 43 basically just summarizes some of the findings of the ISO's April 2007 local capacity requirement report that applied to 2008. And we've kind of narrowed the focus here down to the LA Basin area and Big Creek/Ventura because that's where the aged plants that we were looking at are located, in those two areas. Pardon me.

As you can see, for example, in the LA basin that what they call the local capacity requirement for generation that has to be on-line at the time of peak load is a little over 10,000 megawatts. There's about 12,400 megawatts of installed capacity in that portion of the LA Basin right now. That includes QF generation, some wind, the municipally-owned generation, the generation at SONGS and the market generation, which is pretty much all of the other thermal plants and so forth that are located in that area.

Similar for Big Creek/Ventura. You obviously don't have near as much load up in that area but the local capacity requirement is still fairly rigorous. There's a lot more QF generation up there, substantially more wind. Obviously there's less market generation than in the LA Basin.

What we did in our analysis was assume two things. That the import limit for the LA Basin area would remain at the 9,500-plus megawatts that was identified in the work that the ISO had done.

And we also assumed that the import limit for the Big Creek/Ventura area would increase by 600 megawatts because of the addition of the Tehachapi Renewable Transmission Project, which was not factored into the work that the ISO had done at the time.

We assumed that the load in each of the areas would reflect a pro rata change due to any demand side resources that were added to the system, the energy efficiency and the solar. And then that the local capacity requirement for the area would be equal to the difference between the import limit and the load, the adjusted load for the area.

A couple of other assumptions that we

made. Particularly as far as the Big Creek/ Ventura area was somewhat consistent with what was done in the LCR studies. That 20 percent of the installed wind capacity in that area could be available for LCR. The ISO had assumed in the 27 cases 100 percent all the way up -- they seemed to have significantly fewer megawatts too. That was one of the assumptions that we made.

And as shown on the following graphs, basically we looked at all three of those cases to see if the aged plants were retired, replacement capacity was developed to make up whatever difference was required between the capacity that you lost and what might be covered by renewables or energy efficiency impacts and stuff to try to get a feeling for would we still be able to meet the LCR requirements for those two areas for those three cases.

And basically under those assumptions, that, you know, that the eight plants retired, as they were retired they would replaced by thermal capacity in the system. It appeared to us that for all three of those cases and for all the three different study years that we looked at that you should be able to meet the LCR requirements without a problem.

Now granted that's, we talked about it before, it's dependant on the assumptions that we made as far as location of the new generation and so forth. But using the assumptions that we did it looked like it would meet the --

ASSOCIATE MEMBER GEESMAN: Which you earlier characterized as the worst-case. So are you saying that even using your worst case assumptions you didn't see a problem meeting the LCR?

MR. LARSEN: Yes, yes. When I used the phrase worst-case I probably should of thought of something better.

ASSOCIATE MEMBER GEESMAN: You were kinder toward it than I was.

MR. LARSEN: That was strictly from the perspective of looking at the transmission system right down in the LA Basin by assumption to put the generation on the eastern portion of it. From the LCR perspective it doesn't have that much of an impact because it is all in the same general area anyway.

Dr. Jaske had talked earlier a little bit about some of the coordination we've had with

-- as part of this process. Obviously there was a fair amount between ourselves and Commission staff and Global. Decisions as went through the process. There have been some discussions with the ISO and Edison regarding results of our work. We've kind of summarized it here and Dr. Jaske talked about it.

One thing I didn't mention in here and I don't believe he did either is we have also had some discussions with some of the Edison transmission planning staff about perhaps making available to them some of the data sets that we used so they could kind of do some similar, you know, studies and do a reality check if you will. Those discussions are still ongoing. I don't know, you know, what's going to be the outcome of that. But that has been, been offered.

As far as conclusions of the study. I think we've probably talked about them all several times but I'll go back and revisit them.

The retirement of a little over 4,000 megawatts of generation in the Edison area would require fairly significant upgrades to the transmission just based on the assumptions that we used and the development of significant levels of replacement capacity.

Accomplishing all of those requirements by 2012 would obviously be problematical due to several issues, siting, licensing, funding, acquiring rights of way, whatever. There's a lot of things that would have to be considered as part of the development of a good plan for doing this.

Dr. Jaske alluded to it earlier and he showed it in some of those slides earlier that the increased levels of the energy efficiency and renewable energy resources can have, and the timing of them when they come on, could have a significant impact on how you might ultimately end up making a decision on which plants to retire, when to retire them and so forth. It should be factored in the assessments going forward on this item.

ASSOCIATE MEMBER GEESMAN: So in evaluating that and trying to determine the cost of doing so did you take into account at all the cost to customers of continuing to operate the plants that are 35 or 40 percent less efficient than modern plants?

MR. LARSEN: We did not. Global Energy Decisions did in the follow-on work that they did based on this effort.

ASSOCIATE MEMBER GEESMAN: And we'll get a chance to see that at some point?

MR. LARSEN: I assume so, yes. I'm not going to try to explain it but I certainly --

ASSOCIATE MEMBER GEESMAN: Okay.

MR. LARSEN: I'll talk a little more again about some issues you have to deal with, licensing, permitting, acquiring rights of way and so forth that would have to be thoroughly considered and researched as part of any decision made as far as the retirements are concerned.

And I think the final one here that I really want to stress is a plan, if you will, for going forward should involve obviously all impacted parties, the utilities, the Commission. The generation orders, customers. It should also further address some of the LCR impacts rather than just really very preliminarily like we did at it. And there are a number of operational-type considerations that we just didn't have the time to undertake.

And getting back to one of the items that Dr. Jaske mentioned is the amount of inertia that you have on the system in Southern California to maintain it high enough so you can optimize your imports into the area and so forth is a critical thing that we didn't have the time or whatever to look at. It should be evaluated as part of any future activities on this effort.

I think that's about some of my points. I'd be happy to try to address any questions if I could.

PRESIDING MEMBER PFANNENSTIEL: Thank you, thank you Mr. Larsen. Are there questions from up here?

ADVISOR ST. MARIE: A comment over here.

PRESIDING MEMBER PFANNENSTIEL: Yes, go ahead, Steve.

ADVISOR ST. MARIE: Steve St. Marie from Cal PUC. Mr. Larsen, you're to be forgiven I think for developing the dumb scenario. I recall Mr. Dave Freeman just a few years ago at the Cal Power Authority talking about how we've got to retire all these old plants because they're like me, they're old and they're broken down. So there's a lot of reason to consider retiring these plants.

But the point that I want to make here is that even if the plants are not valuable these sites are valuable. They're central to load, they are already connected to transmission systems that are already built right there. They are brownfield plants. It has been the policy of the CPUC at least since January 2004 that in the loading order when you finally get to the point of building plants, brownfield sites are the way to go before you try to build anything in a new place.

We have a sclerotic society that wants nothing new built anywhere near anything else or where anybody lives. And certainly no one who lives in the areas of these plants would have any reason to complain, would have any legitimate reason to complain that oh my gosh, there's a power plant that is going to be there.

You know, every town may want one of these sites for a park or for condominiums or for something else that it would like to have. But for California's sake these sites need to remain as power plants. This is a case where the overall good may not be coincident with the good of any one little neighborhood that would like to maximize its own property values by getting rid of all power plants that are anywhere near where they are and making it into a pristine nature preserve once again.

The power plants are there, this is valuable to California. These things could be picked off one by one if people read the studies that are done here and read them incorrectly or read them maliciously in such a way that they get the idea that it would be cheap and easy to build some other power plant somewhere far away.

You know, to make the electric system work we're going to have a much better electric system and a much cheaper electric system if we can keep power plants on these sites.

ASSOCIATE MEMBER GEESMAN: And I guess I would zero in on what Steve said in terms of when we finally get around to building plants. We are six summers after the California electricity crisis. Not really done a lot about bringing new capacity on-line, particularly in the Southern California Edison service territory.

Pat Wood when he left the FERC, and right now I can't recall if that was June of 2004 or June of 2005. But when asked how he thought all of us had done, including the FERC, on dealing with the infrastructure challenges in the wake of the California crisis he said, I'd give us about a D-plus. Well since he left I don't think that we have exactly improved our grade either.

So in 2005 after a couple of years of study we made the fairly straightforward observation that we needed to move forward rapidly with long-term procurement and suggested that it was financially imprudent from the customer's perspective for utilities to continue to rely on these aging plants. And we set up what we thought would be an orderly retirement and replacement. I emphasize replacement calendar that would have them off their reliance on 50 listed facilities by the year 2012.

I really think that this study does not help things by trying to tar the state's renewables and efficiency policies with some notion that well it would be even better if we just drug our feet a little bit longer and kept these jalopies in service because we'd have more renewables and more efficiency as a result.

I think we are moving forward as quickly as we can, and state policy is to move forward as quickly as we can with respect to those preferred resources. But we still haven't moved forward with a very aggressive, long-term procurement program. And for you to overlook the repowering opportunities at these sites I think is a pretty serious oversight. And I'm sorry that we didn't structure the scenario better for you to evaluate.

I do think this ought to occupy a high priority for us and for the ISO and for Edison going forward. PG&E and San Diego seem to get it. Their long-term procurement policies, in the opinion of our staff, comply with our 2005 IEPR recommendations. But Edison is the outlaw here and I think Edison is where the problems persist. I look forward to hearing the Edison presentation later this afternoon.

ADVISOR ST. MARIE: One more comment. Commissioner Bohn and I did attend the reopening of the Long Beach power plant, which is now a revived peaker. And it was a day when there were lots of congratulations all around on that.

ASSOCIATE MEMBER GEESMAN: And that causes me concern because that plant and the Edison peakers that were built so hurriedly for the summer represent an ad hoc approach in response to crisis that we are stuck with if we don't proceed in an orderly fashion to retire and replace these plants.

That's why I think the opportunity exists for both commissions to pursue a rational policy of replacing this aging capacity.

PRESIDING MEMBER PFANNENSTIEL: We have a presentation that was handed out to us from Edison and I think we should go through that now, we're running out of the day. So if we could have the Edison presentation loaded and some discussion about that.

DR. JASKE: While the Edison presentation is being loaded up let me just say that in the staff report, Table 7, there are some levelized cost comparisons of the original cases versus the six that were presented today. Also in the appendix authored by Global Energy, I believe that's Appendix B, there is some detail about the production costs just for the Edison trans area. So there are some cost information about these consequences that are there but we were not prepared to go into those in detail today. Mr. Minick.

MR. MINICK: Good afternoon Commissioners and guests. I guess you guys are guests. This will go relatively quickly. First I would like to make a few evident or I guess non-controversial statements. We need a robust transmission grid so --

PRESIDING MEMBER PFANNENSTIEL: I'm sorry, please introduce yourself for the record.

MR. MINICK: I'm Mark Minick.

PRESIDING MEMBER PFANNENSTIEL: Thank you.

MR. MINICK: M-I-N-I-C-K, manager of resource planning at Southern California Edison.

We need a robust transmission grid so we have to consider how we continue to maintain the grid in a robust manner. Which might mean adding new resources before you retire old resources and I think we can all agree to that.

Transmission modifications are often controversial, both from local siting and other reasons, so some of these might take longer than the three to five years you might anticipate doing them by 2012, so give us some time to do that.

I am now involved very much with the air quality district of Southern California and they're having a real difficult time giving out siting permits for some of these new plants that were assumed to be constructed here. It might be easier, Mr. Geesman, if we did allow some of the credits from existing plants to be used to build plants at the same site.

ASSOCIATE MEMBER GEESMAN: Many have argued that the South Coast was able to find offsets as soon as your company said that some more were needed.

MR. MINICK: I did testify before them or talk to them about it. To the best of my knowledge, and I am not an expert yet, I am going to meet with them next week. They did free up some credits but I think there is also a controversial issue between the EPA and the AQMB about whether they could be giving all these offsets away because we are a non-attainment area. So we need to at least address that.

Lastly, I don't like to admit it but in some cases SONGS has two units down. And when I said robust grid I mean we have to be able to entertain that possibility. It has happened for only a few days in the last 15 years but it might happen again the future so that's something we need to study.

And I am well aware of the fact, as was represented here, that new plants do not have the same inertia benefits of old plants. And inertia is what drives skid limits and what allows us to import. So we do definitely have to study that.

Now my presentation. I think you've made a good start. I regret that I didn't get involved sooner and made some comments to Mike and his staff regarding some of the scenarios that we may have built or some of the things we may have looked at before we built some of these scenarios.

The information they had basically said let's look at plants that are in the siting and licensing queue and that's what they did but that may not be the best sites to necessarily look at for extending the system.

ASSOCIATE MEMBER GEESMAN: Mark, pause for a minute and tell me why that would make any sense at all. I mean, you know what kind of people apply for spots in the queue.

MR. MINICK: I agree you have to make some assumptions about what might be built. And the ones that have asked for the queue are ones that are at least taking the time and effort and spent the money and deposited with us to take a look at the transmission interconnections. That's all I'm saying, okay.

ASSOCIATE MEMBER GEESMAN: I would submit it's the same quality of input that you'd get from surveying those in the queue outside the Westwood Theater. I think that your company and our staff and the ISO can bring a lot more enlightened judgment to the question than simply taking a, I would argue not even random sample of people that previously have expressed an interest in developing power plants.

MR. MINICK: I agree we can do better, we'll leave it at that. We think a future analysis should look at import capability, inter-tie outages, some more NERC and WECC reliability standards.

And then I'd like to help build cases where we look at maybe the extremes. And this might be an extreme, it might not be an extreme enough extreme. So that we could take a look at the emission effects, the water and fuel usage and the various possible renewable and other generation siting needs.

There are some cases where you'd build a lot of wind in one area and other cases where you'd build a lot of wind in a different area. This will affect our grid.

ASSOCIATE MEMBER GEESMAN: And you mentioned water; 316B is going to drive this process probably more than any of us knew a few years ago.

MR. MINICK: That's right. And one thing that I didn't announce is the Coastal Commission does want to shut a lot of these plants down at the coast. And unless we build new plants on the coast that are not once-through cooling but multiple passes through in the water cooling we probably can't get siting and licensing to build the new plants at the coast anyway.

The ISO is coordinating a collaborative study. I think we're going to have a conference call with them a week from Friday and we're very involved now with this particular study. Right now it looks like it is a very comprehensive study and we think it's the next logical step.

This was a reasonable simulation, at least when we looked at the data, of the information that we used. The assumptions might have been flawed and we needn't go there again. We don't necessarily agree with the specific retirement conclusions. I would say in general it's a starting place. It says that zero isn't the right answer and 8,000 megawatts isn't the right answer. It's something in-between over period of time that we can define as the best way to basically retire the older plants and put in new plants. But we do need to keep some generation in the basin.

We do believe that the upgrades, at least my transmission people do, are a little more extensive and costly than proposed. I am not going to say it's triple or quadruple the costs because I haven't seen the data but it is a little more costly than was shown here.

And we would like to be very much involved in any future analyses.

This is just a pictorial view of some of the information that was shown before. What the existing capacity is and what the local capacity requirements are and what it would be after the retirements. The local capacity requirements will change with the mix of generation and loads and the ISO really hasn't done a longer term analysis of this yet. We have some indication that it might go up next year but again they are going to have to tell us what the long-term local capacity requirements might be.

The same way in the Ventura area. This is another pictorial of what it looks like when you retire those particular plants.

As I previously identified, bringing new baseload generation to the LA Basin before 2012 may be problematic. Right now the Air Quality Management District is looking more at peaking facilities because of the offsets they're allowing. There are some limitations on run times of some of the resources. So bringing in new baseload resources might be difficult.

And again we definitely have to address the cost allocation. It is not a huge cost allocation but we definitely have to address that particular issue.

To the best of our knowledge the ISO study, and they were supposed to be here today, will be completed about the fourth quarter of 2008. It is a very complex study. I think this is a reasonable time in which to complete it.

We are going to be involved with other parties. It basically says it is going to be an iterative process. Screening and going through some things. And some plausible scenarios and looking at some worst cases.

And our goal, I think, is to come back to you and other regulators and saying, this is what we think is doable and possible in the time.

And that is my presentation, the other are backup slides.

PUC COMMISSIONER BOHN: Can I just express -- I'm kind of a newcomer to this. That kind of a presentation just worries the heck out of me because it talks about studying and studying and studying and studying. And if I were running your company I would have been doing this for about the last four or five years at least and I'd have a whole series of alternative scenarios with contingency plans already on my chief executive's desk.

And I can recognize that there are a series of problematical possibilities depending on the goofiness with which we regulate and the odds and ends of fickle fashion if you like. But what I take away from that presentation, perhaps incorrectly, is a kind of a treading water approach. And I don't get a sense that anybody is very serious about dealing with this.

I would have thought that you all would be all over this plan and be able to sit down and take that presentation apart and simply say look, this is what we're going to have to do and this is the way we're going to do it. And we think this plan ought to be backed up and we had this problem with transmission. Rather than coming and saying, well we've got to keep studying it.

Maybe I got it wrong but I'm just not very impressed with that.

MR. MINICK: Edison has done a study. That study has been shown to the ISO. But the ISO does local capacity requirement studies, we don't. The ISO basically is looking at a more extensive study for all the utilities, not just Edison. And so we can't say that our study is the end-all.

Regarding tearing apart your staff's particular analysis. I didn't think I was supposed to necessarily do that here. We can definitely give them more detailed comments.

PRESIDING MEMBER PFANNENSTIEL: Could we hear from the ISO. Thanks Mark.

MR. TOBIAS: My name is Larry Tobias. I work at the California ISO, specifically I am in regional transmission. What I would like to say, at least initially, is acknowledge the comments form the Commission here. My plan is to make use of the transcript to make sure that everything that is said is reflected in this analysis. But somewhat answering a summation of this before going into some more details that I'd like to provide.

The end product will be one that this is a plan that we can proceed with. It's not this scenario, that scenario, so on. But it encompasses what's most economic, what's best from a social aspect. What's doable, feasible, looking at all of that in a very simple way.

For instance the study plan, and it is just a very rough draft one to start with because I very much wanted to leave room to hear what everyone thought of this. Anyway, the pecking order is simply that the best thing to do is if we have less load that needs to be served that could be accomplished a lot of different ways, conservation, demand side management, local renewables, other generation.

Certainly with local generation where new plants can be established if at all possible on the same site. By example that did not turn out to be a possibility in San Francisco.

But at for example Mirant's Pittsburg

power plant where we did take Pittsburg 7 off of our mark. There's quite a room there where something else could be established on-site without waiting for more transmission or anything to take the place of that. And that is something that we plan on working with Mirant. That as well as Contra Costa. Those are just examples.

But that's the detail of going through this process to make sure that we come up with a plan that we can proceed with. And certainly with all plans they can change on a regular basis so we analyze them annually, that is just the nature of planning. So we don't create something set in concrete. But nevertheless we know the goals and we keep analyzing it every year so that we try to meet the goal, we meet that goal by that date.

What forms the foundation for what we have is not only what the CEC has facilitated and Navigant Consulting has done, because we have talked with them, we know the extent that their studies have been done, what else is needed. Southern California Edison talked about that a little bit more.

But on another note by comparison for almost a year, and we hope to reach a substantial conclusion by the end of this year, is a study of all of these old power plants, and particularly it covers the ones with once-through cooling for the most part in Northern California. So that's ongoing. That's just speaking entirely for myself and what I am able to do in recognizing that we're going into the third IEPR where retirement of old power plants has been part of that.

So this has been something that for four or five years as part of PG&E's annual planning process they have included in there the retirement of old power plants. They have included in there local capacity requirements. Before that reliability must run. And so they take that and look far enough out so they can anticipate it.

Granted that at the ISO, for instance, we were one year contracts, one year studies. PG&E was looking farther out. What can they do to reduce their capacity. They're not dependant on what we're doing at the ISO if we're limited in our ability of looking out in the future. But this is what PG&E has done. This is the interaction back and forth between myself and them.

This is what will happen starting with a conference call next Friday with all three utilities. As much as I'm aware of San Diego Gas and Electric is automatically in the loop. And you can see from the presentation by Southern California Edison that they will be as well.

I didn't want to get into a lot more of the detail of the process and so on other than the schedule is very important. Clearly this should have been done by now, you know. And the effort on once-through cooling that's being addressed, that will be done before this looking at retirement. They're both connected.

And so once-through cooling can go through and say, these are the power plants where you can utilize other wet cooling, closed loop process rather than water out of the delta or the ocean. These are units where you can use dry cooling and what that means and so on and so forth. Including looking at the nuclear power plants.

But what transmission do you need and to where? That's where this study will fall into place. And again the objective is to establish a plan that we can move forward with. Very likely it will be a phased plan unless there is an exact determination that at this point in time these units when they need to renew their licenses for utilizing once-through cooling, that's not in effect. And at this point in the time that's not in effect. Those are definite dates. Then we will move on and see exactly what we can do and how quickly we can do it.

Rolling back into the schedule though. Granted though that the study plan that I sent out has 18 months on it approximately. It's less than that now, between now and the end of next year. I tell you, I would like to see this completed as quickly as it can be.

In the past my experience and what I have been involved in at the ISO, and very much with the cooperation of Southern California Edison and San Diego Gas and Electric, have seen these type of things accomplished within nine months. It can be done very quickly if a lot is done in parallel. I don't know if it will take 18 months, that's on the outside. I would like to see it done quicker if possible.

It all sounds very ambitious but I'm aware of all the complications and what needs to be included in here. And it's certainly a challenge when normal planning is looking at low-growth. So low-growth changes and generation changes and you're marching forward and building the system and staying up with that.

Generation retirement is taking a step back and then you fold into that the very real requirement that replacement generation as much as possible should be renewable. And that we need to support renewable with other generation because we need to account for both the energy and the capacity of renewable. When is renewable available. And it can supply a lot of energy but perhaps not when the capacity is needed. So you need the right mix.

On a much smaller scale when we addressed the evolution of transmission generation in San Francisco. That's exactly what we looked at such that we can meet the daily load curve through the year, both capacity and energy. And we were assured of doing that. It's very much an additional layer of requirements for actual system operation but we're willing and very able to support that, such that we're reliable on a day by day basis.

A couple of things to note that come

into here that are specific and we take into account. That is, for instance what everyone, not just the ISO, tried to do. But everyone leading up to last year where the load was much higher than what anyone anticipated. Fifty thousand megawatts in the state instead of the previous year I think it was a little over 42,000. It hasn't been very different than that this year.

The real load out there this year is more than 50,000 megawatts, we just haven't seen it. It's not really something that we want to plan for if we see extreme temperatures not to be able to serve all the load. So that's the objective that we want to shoot for and that is the layer of operation that the ISO is very aware that can add into that.

There is perpetually many challenges to all of the reliability criteria that we use to plan the system, operate the system. But our goal is to maintain what's there. We have NERC criteria, WECC criteria, criteria established by the ISO. In parallel with this there's a stakeholder meeting next month that I'll be leading on revising the ISO criteria so that we stay up to date and in sync on all of these different fronts.

We've planned the system right for what we expect to happen. Right now on criteria perhaps it could seem what's published on our website might be a little in arrears. In actual planning we're already planning based on who we think that criteria will be revised. It's just taken time to actually reform a group to look at that. But that's the fulls scope of it.

It can appear on some fronts that we're in arrears but we're not. So hopefully when, if I come to your next workshop in September I'll be able to tell you, we have everything in place. We have a final study plan, we've had a stakeholder meeting and we're ready to go to fill in all the missing elements of what's been done so far.

Any questions? I apologize for making a speech. I know it can seem that way coming from myself and it's usually what I'll say at stakeholder meetings. But I'm very open to direction and comments very much.

ASSOCIATE MEMBER GEESMAN: Well I'm glad that you were here and I'm glad to hear about your study. I'm also glad that our workshops are sufficiently informal that we don't put people under oath because I think your comment about not being in arrears would border on perjury.

We have been after you for a couple of years to try to get your attention as an institution on this problem and I think it's been a long, slow, hard pull. Hopefully that's been accomplished and hopefully this effort over the course of the next 9 months or 18 months, whatever it takes, can address these problems in a little bit more urgent fashion than any of us have been able to do over the course of the last six years.

I will say that one of the, one of the ongoing difficulties that the ISO's perspective brings to these questions is your operational role, which is extremely vital to the state's economic and reliable existence, often in my judgment, clouds the unintentional role that you may have in stalling or deferring needed investment in new infrastructure.

You have never met a power plant you didn't like. You have never met an existing facility that isn't essential. Or at least that's the way it comes across. And I don't think your voice has been quite as strong in advocating the necessity of new investment and the replacement of existing facilities that simply can't be relied upon indefinitely.

And in the five years that I have served on this Commission I have to tell you the last four we have gone through this very debilitating process of almost secular prayer sessions about how we're going to do this summer. Are we going to have the crisis this summer. That's no way to exist. California doesn't want to live like that. And I think that it's the responsibility of the very state agencies and the ISO and the utilities to get us out of that jam.

Frankly I don't think that other than in an operational sense the ISO has pulled its weight in that regard. And I hope you're a stronger voice for investment in infrastructure going forward than you have been in the past.

MR. TOBIAS: Commissioner Geesman, forgive me. A great deal of my comments had to do with my interaction with PG&E and what we've accomplished and how far we're along but not necessarily the ISO or the other two utilities.

So I can't really answer as to why that's so other than what I have been able to accomplish by example and what I hope to have happen for the ISO-controlled grid, all the utilities involved in that.

ASSOCIATE MEMBER GEESMAN: Mark mentioned inertia and I know the value your grid operators place on inertia. I would suggest inertia is the official corporate policy in Rosemead and unfortunately it tends to infect us all with respect to promoting new infrastructure. And I think all of us need to do more to try and overcome that.

MR. TOBIAS: Yes, I understand that completely.

PRESIDING MEMBER PFANNENSTIEL: We appreciate your being here. As you can imagine as we're trying to gather the information we need to put it into this year's IEPR report we once again will be making virtually the same recommendations we have made in past IEPRs. And it gets more difficult to have the sort of upbeat sense of people are listening and therefore will do something about it. We'll probably end up being somewhat more strident this year in this area since it does look like we're not being -- the urgency that we have put to it isn't being heard.

Clearly a study is under way. Whether

it be 9 months or 18 months it's still years later than we had anticipated that it would or should be done.

MR. TOBIAS: Yes.

PRESIDING MEMBER PFANNENSTIEL: So again I appreciate your coming to tell us where it is and thank you. Are there other questions for the ISO? Thank you very much.

MR. TOBIAS: Okay.

PRESIDING MEMBER PFANNENSTIEL: Other stakeholders, other participants, others in the audience who have questions or comments to offer?

Anybody on the phone? Nobody on the phone. Dr. Jaske.

DR. JASKE: I propose to close with just one comment. And that is, despite the optimism of Mr. Tobias about his ability to deliver a plan it is not at all clear to me how a plan gets executed. This Commission, the PUC, the ISO, do not have the power to corral all of the moving parts that we're talking about here today and make it happen unless they all get together and act cooperatively.

And you have the added complications now, much more visible, of the South Coast AQMD and the State Water Board pursuing their particular interests that focuses especially on Southern California. As it turns out that's their sole focus and it just makes the decision-making process, the action upon an action plan proposal, all the more complicated.

So you collective decision-makers need to be thinking about how any plan brought forward to you could actually be evaluated and some variant of it implemented in as timely a way as possible.

PRESIDING MEMBER PFANNENSTIEL: I believe we understand that. I think we are through waiting for the information we need upon which to make those decisions. Thank you.

If there is nothing further we will be adjourned.

(Whereupon, at 4:50 p.m., the Committee workshop was adjourned.)

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CERTIFICATE OF REPORTER

I, JOHN COTA, an Electronic Reporter, do hereby certify that I am a disinterested person herein; that I recorded the foregoing California Energy Commission Committee Workshop; that it was thereafter transcribed into typewriting.

I further certify that I am not of counsel or attorney for any of the parties to said workshop, nor in any way interested in outcome of said workshop.

IN WITNESS WHEREOF, I have hereunto set my hand this 27th day of August, 2007.